ZARGON ENERGY TRUST

2005 Annual Report

SUSTAIN|ABILITY

Structured to create value

TRUST HIGHLIGHTS

FINANCIAL **($ million, except per unit amounts)**	**2005**	2004	Percent Change
Income and Investments			
Petroleum and natural gas revenue	**162.72**	123.97	31
Cash flow from operations	**84.97**	63.75	33
Cash distributions	**37.44**	10.70	250
Net earnings	**35.37**	20.63	71
Net capital expenditures	**54.68**	56.27	(3)
Balance Sheet at Year End			
Property and equipment, net	**253.32**	209.74	21
Bank debt	**10.34**	14.23	(27)
Unitholders' equity	**144.61**	120.62	20
Total units outstanding (million)	**18.99**	18.61	2
Per Unit, Diluted			
Cash flow from operations	**4.51**	3.40	33
Net earnings	**2.19**	1.20	83
Cash Distributions ($/trust unit)	**2.32**	0.70	231

OPERATING			
Average Daily Production			
Oil and liquids (bbl/d)	**3,697**	3,416	8
Natural gas (mmcf/d)	**27.87**	28.84	(3)
Equivalent (boe/d)	**8,342**	8,222	1
Equivalent per million total units (boe/d)	**445**	447	–
Average Selling Price (before risk management losses)			
Oil and liquids ($/bbl)	**57.15**	45.37	26
Natural gas ($/mcf)	**8.41**	6.37	32
Proved and Probable Reserves at Year End			
Oil and liquids (mmbbl)	**15.35**	14.36	7
Natural gas (bcf)	**68.50**	69.56	(2)
Equivalent (mmboe)	**26.77**	25.95	3
Equivalent per total unit (boe)	**1.41**	1.39	1
Wells Drilled, Net	**53.5**	49.5	8
Undeveloped Land (thousand net acres)	**367**	376	(2)

NOTES:

Throughout this report, the calculation of barrels of oil equivalent (boe) is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil.

For net capital expenditures, amounts include capital expenditures acquired for cash and equity issuances.

Total units outstanding include trust units plus exchangeable shares outstanding at period end. The exchangeable shares are converted at the exchange ratio at the end of the period.

Cash flow from operations is a non-GAAP term that represents net earnings except for non-cash items. For a further discussion about this term, refer to page 29 of the report.

Cash distributions to unitholders commenced subsequent to the reorganization of the Company into a Trust, effective July 15, 2004.

Average daily production per million total units is calculated using the weighted average number of units outstanding during the period, plus the weighted average number of exchangeable shares outstanding for the period converted at the average exchange ratio for the period.

To Zargon, a sustainable oil and gas trust must fund a sufficient reinvestment program to indefinitely maintain reserves, production and distributions on a per trust unit basis without sacrificing the underlying quality of assets or the Trust's financial condition.

SUSTAINABILITY

Structured to create value

Zargon expects to maintain stable production, reserves and distributions on a per trust unit basis, while distributing approximately 50 percent of the cash flows attributed to our unitholders. This sustainability objective is to be accomplished with ongoing oil and natural gas exploration and development capital programs funded by the remaining 50 percent of our Trust's cash flows.

In addition to our sustainability strategy, our business model provides for the opportunity for a modest level of growth on a per trust unit basis through corporate and property acquisition programs funded from cash flows attributable to our exchangeable shares, the cautious use of unutilized bank facilities and/or accretive equity issues.

Building on its successful history, the Trust will continue to pursue the complementary business strategies of first, exploring and developing natural gas reserves, while second, exploiting existing oil reservoirs.

PRESIDENT'S MESSAGE

THE YEAR IN BRIEF

Zargon Energy Trust reported record financial and operating results in 2005 during its first full year of operation in a sustainable trust format.

Fueled by record oil, liquids and natural gas commodity prices, Zargon delivered year-over-year gains of 31, 33, and 71 percent in revenue, cash flow from operations and net earnings. During the year, cash flow from operations climbed $21.2 million to $85.0 million or $4.51 per diluted unit, a 33 percent increase from the prior year's $3.40 per diluted unit. These large increases in cash flow from operations were shared with our unitholders. Over 2005, the Trust distributed $37.4 million to unitholders ($2.32 per trust unit) which was equivalent to payout ratios of 51 percent on a trust unit basis and 44 percent on a cash basis (exchangeable shares do not receive distributions).

Operationally, Zargon delivered a very strong year in 2005 with exploration and development capital expenditures of $52.3 million, and only $2.4 million of net property and corporate acquisitions. With these capital programs, Zargon grew production volumes by one percent, grew proved and probable reserves by three percent and delivered proved and probable finding, development and acquisition costs ("FD&A Costs") of $14.11 per barrel of oil equivalent. The capital program and distributions were funded by cash flow from operations, minor trust unit incentive plan issuances and an equity issuance for a very small corporate acquisition, leaving Zargon's year end debt net of working capital position (excluding the unrealized risk management liability), at a very low $27.5 million.

2005

HISTORY OF VALUE CREATION AND RETURNS

Throughout our thirteen-year public history, Zargon has successfully focused on a value creation strategy as evidenced by the following statistics:

- **Forty-nine consecutive quarters of positive net earnings; a record that we believe will be extended into the foreseeable future.**
- **Over our history, Zargon has raised a total of $50 million of unitholders' equity. With the February 2006 distribution, Zargon has returned this entire amount back to its unitholders, while building a business entity with a market capitalization of more than $600 million.**

SUSTAINABILITY STRATEGY

Zargon's most important 2005 accomplishment was to successfully demonstrate the functionality of our sustainable trust model.

When Zargon Energy Trust was created in mid-2004 to provide a more tax efficient structure, our Trust acquired all of the operational, financial and intellectual assets from our predecessor company, Zargon Oil & Gas Ltd. The decision to acquire all of the predecessor's assets, without the disposition of its exploration assets to a related company, was driven by our desire to build a trust that would have sufficient financial, intellectual, undeveloped land and property resources to sustain its operations by reinvesting approximately 50 percent of the cash flows from operations. This focus on sustainability, in a value creation context, represents the fundamental overriding objective of our organization.

To Zargon, a sustainable trust is defined as a trust that has a sufficient capital reinvestment program to indefinitely maintain reserves, production and distributions on a per trust unit basis. This sustainability objective must not be accomplished through the deterioration of the underlying quality of assets, the deterioration of the Trust's financial condition or the acceleration of the Trust's taxability horizon. As identified on the next page, our 2005 results met sustainability targets in all six of the measured parameters.

The reorganization of Zargon Oil & Gas Ltd. into Zargon Energy Trust has been accounted for using the continuity of interest method. Accordingly, the consolidated financial statements reflect the financial position, results of operations and cash flows as if Zargon Energy Trust had always carried on the business of Zargon Oil & Gas Ltd.

Zargon's most important 2005 accomplishment was to successfully demonstrate the functionality of our sustainable trust model.

2005

KEY SUSTAINABILITY ACHIEVEMENTS

Zargon defines its sustainability targets in terms of the following six parameters, while distributing approximately 50 percent of Zargon's cash flow. In 2005, Zargon met these targets.

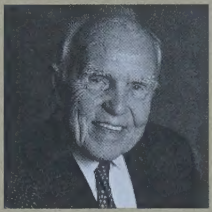
- **Production:** Zargon's production averaged 445 barrels of oil equivalent per day per million trust units, a level within one percent of last year's rate of 447 barrels of oil equivalent per day per million trust units.
- **Reserves:** Zargon's year end proved and probable reserves were 1.41 barrels of oil equivalent per total trust unit, a one percent gain over the prior year.
- **Distributions:** Cash distributions were $2.32 per trust unit and represented 51 percent of the year's cash flow from operations on a per diluted trust unit basis (44 percent of the Trust's cash flow from operations). By the end of the year, base level monthly distributions had been increased to $0.18 per trust unit from the 2004 level of $0.14 per trust unit.
- **Balance Sheet Quality:** Zargon's year end debt net of working capital (excluding the unrealized risk management liability) of $27.5 million represented a debt to 2005 cash flow multiple of 0.3 years, a slight improvement from the 2004 year end multiple of 0.4 years.
- **Asset Quality:** Zargon's asset quality in terms of average crude gravity (30 degrees API), and natural gas/oil mix (56 percent natural gas production) did not change materially in 2005. The year end proved producing, proved total and proved and probable reserve life indices also remained essentially unchanged at 5.4, 6.1, and 8.5 years, respectively. In 2005, Zargon was successful in meeting its finding and development cost objectives without booking any proved undeveloped reserves.
- **Tax Horizon:** Zargon's quantity of tax pools increased in 2005 to a year end balance of $90 million, as compared to the 2004 year end balance of $79 million.

This emphasis on sustainability reinforces Zargon's objective to focus on value creating activities. By accepting the sustainability challenge with a 50 percent distribution policy, Zargon must, through its exploration and development capital program, add two barrels of oil equivalent reserves through spending the cash flow derived from each barrel of oil equivalent produced. Simply put, in order to meet its sustainability objectives, the Trust must deliver a recycle ratio (defined as the Trust's cash flow from operations on a barrel of oil equivalent basis divided by proved and probable finding and development costs on a barrel of oil equivalent basis) of two times, from its organically generated exploration and development programs. This proved and probable recycle ratio must reflect cash flows from operations (not property cash flows), and must make an allowance for the future capital costs to develop the reserve base. In 2005, Zargon was successful in meeting this objective. *Although it is anticipated that there will continue to be year by year variances in the efficiencies of Zargon's exploration and development capital programs, the long term delivery of an average exploration and development recycle ratio of two, continues to be a fundamental and necessary target of our sustainable trust strategy.*

In addition to maintaining stable reserves per trust unit, the sustainable trust model requires Zargon to maintain production rates on a per trust unit basis. We calculate our theoretical base decline rate as the inverse of our proved producing reserve life index. At the end of 2005, this calculation estimates Zargon's proved producing decline at 19 percent which implies Zargon must add approximately 1,550 barrels of oil equivalent per day of new production every year to replace the naturally occurring production declines. Based on this calculation, Zargon's 2005 exploration and development program was successful in replacing production volumes at an acceptable $33,500 per barrel of oil equivalent per day. This calculation does not take into account that during the year, Zargon's previously most prolific well at Progress, Alberta watered out, thereby eliminating

2.87 million cubic feet per day of natural gas (480 barrels of oil equivalent per day) or almost six percent of Zargon's production. Including the loss of the Progress well, our 2005 exploration and development program delivered production additions at a very efficient rate of $27,000 per barrel of oil equivalent per day. Similar to the reserve replacement requirements, efficient production addition costs are a key benchmark that we use to evaluate our exploration and development programs. *In particular, our 2006 production addition targets should be readily achievable, due to our large inventory of shut-in West Central Alberta wells scheduled for tie-in. Furthermore, the Trust now has a lower concentration of risk as no single well currently represents more than three percent of production.*

Craig Hansen
President and Chief Executive Officer



John McCutcheon
Chairman of the Board

MODE OF OPERATIONS

Over its thirteen-year life, Zargon's success has been facilitated by the two distinct, but complementary initiative, of the efficient exploitation of oil properties, and the seismically-driven exploration for natural gas. Our large inventory of underdeveloped oil properties and undeveloped natural gas prospective land provides Zargon the resource base to support our sustainable trust initiatives.

Our oil exploitation business begins with the identification and acquisition of properties with a large oil-in-place that are generally located in the Williston Basin. We then deploy improved recovery techniques or geologically driven exploitation concepts to develop additional reserves. Through numerous historical acquisitions and associated drilling and development programs, Zargon has assembled a working interest inventory of 176 million barrels of exploitable oil-in-place.

Our natural gas exploration business explores for shallow and medium depth natural gas reservoirs based on seismic, geological, and reservoir engineering concepts. Our strategy is to acquire large contiguous land blocks with multi-zone potential and reduce exploration risk by applying advanced seismic and detailed geological mapping. The resource inputs for our natural gas exploration business are seismically or geologically prospective undeveloped lands, preferably in areas where we control natural gas facilities. Through large historical Crown land purchases, we have expanded our natural gas exploration and development activities from primarily the Alberta Plains to include selected areas of West Central Alberta. Based on these prior acquisition programs, Zargon continues to hold a large inventory of 367 thousand net acres of undeveloped land that provides the foundation of our natural gas exploration program.

In 2005, Zargon achieved strong operating results in each of its three core areas. Once again, the Alberta Plains core area team was able to sustain production and reserves with a capital reinvestment program of only 42 percent of the core area's cash flow. Alberta Plains FD&A costs averaged $14.36 per barrel of oil equivalent in 2005 and were primarily driven by Jarrow drilling successes. In 2006, a similar capital program is planned, but with an additional emphasis on down spacing development projects for the Jarrow, Hamilton Lake and Ukalta properties.

Despite suffering a significant reserve and production loss at the Progress property, Zargon's West Central Alberta core area team delivered much better exploration results in 2005 than in the previous year. Notable exploration successes were realized in each of the Peace River Arch, Greater Highvale and Pembina properties. If the 0.66 million barrels of negative adjustments for the

Progress well are excluded, the West Central Alberta proved and probable FD&A costs were an acceptable $15.48 per barrel of oil equivalent. In 2006, Zargon plans on building on its 2005 West Central Alberta successes by tieing-in 12 net wells and by continuing an active program to explore for medium depth and medium risk seismically defined targets.

The Williston Basin 2005 successes came in two manners. First, an active exploitation drilling program added 1.32 million barrels of oil equivalent with a strong proved and probable FD&A costs of $8.78 per barrel of oil equivalent. Specifically, high rate and large reserve wells were added through the Pinto, Saskatchewan and Truro, North Dakota development programs. Second, consistent with prior year's historical pattern of positive Williston Basin reserve revisions, 0.66 million barrels of oil equivalent of proved and probable reserve revisions were recognized. These revisions were primarily due to increased reservoir recovery factors recognizing the positive performance pertaining to pre-2005 waterflood modifications or implementations. In 2006, Zargon plans to continue with its successful Williston Basin capital programs focused on exploitation drilling and waterflood modifications/implementations.

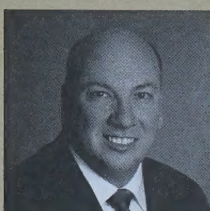
GROWTH STRATEGY

In addition to our sustainability strategy, our business model provides for the opportunity for a modest level of growth, on a per trust unit basis, through corporate and property acquistion programs funded from the balance sheet. Specifically, this additional capital is sourced from the use of cash flows attributable to our exchangeable shares, the cautious use of unutilized bank facilities and/or from accretive equity issues. This capital will generally be directed to acquisitions focused on the replenishment of our feedstock of undeveloped natural gas exploration acreage or our underdeveloped oil exploitation properties. As these acquisitions will not be funded by cash flow, they will be subject to different investment criteria than our exploration and development programs. More specifically, these acquisitions must provide undeveloped land or underdeveloped oil property resources that can support future exploration and development programs that meet our sustainability criteria.

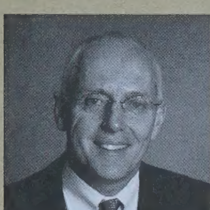
Over the last few quarters, commodity prices and the related industry costs to acquire undeveloped land and underdeveloped oil properties, have in our opinion, been fully priced. Consequently, in 2005 we continued to remain cautious about aggressively using debt or equity capital to fund larger property or corporate acquisitions.

DISTRIBUTION POLICY

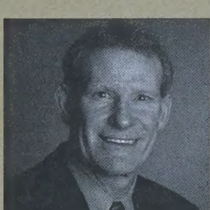
In order to evaluate the effectiveness of a sustainability strategy, there must be a reference to the long term hydrocarbon commodity prices assumed, since the cash flows generated by very high commodity prices will support sustainability targets at much lower capital reinvestment ratios than could be supported in a low commodity price environment.



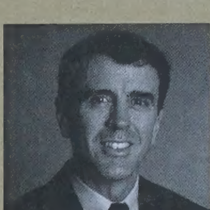
Brent Heagy
Vice President,
Finance and Chief
Financial Officer



Mark Lake
Vice President,
Exploration



Dan Roulston
Executive
Vice President,
Operations



Ken Young
Vice President,
Land

Therefore, to clarify our sustainability targets, Zargon discloses the long term commodity price assumptions that are incorporated in our current base distributions.

Zargon's current $0.18 per trust unit monthly base distribution has been set assuming long term commodity prices of US $50 per barrel (WTI oil) and US $8 per mmbtu (NYMEX natural gas). In circumstances such as in 2005, when commodity prices exceeded Zargon's long term commodity price assumptions, Zargon will consider declaring, on a semi-annual basis supplemental distributions to reach our stated goal of distributing approximately 50 percent of the Trust's cash flows attributed to our unitholders. Conversely, if commodity prices fail to meet Zargon's long term commodity price assumptions, Zargon will have to recalibrate its sustainability model which would likely result in a reduction in the base distribution levels.

OUTLOOK

In the last twelve months, very little has changed in the industry in terms of outlook and trends. Crude prices have twice reached US $70 per barrel and by most standards seem very strong in the face of historically large inventories. Although volatile, average natural gas prices have also exceeded many expectations despite high levels of storage. With the extremely high revenues and cash flows, our industry is clearly in a highly prosperous phase, which has resulted in significant cost pressures due to a very high demand for materials and services.

Assuming that these trends continue throughout 2006, Zargon will respond as it did in 2005, sustaining reserves and production by exploring our undeveloped land holdings and exploiting our oil-in-place resources while doing our best to control costs. Without a vigorous land, property or corporate acquisition program, we believe that our current inventory of opportunities will support natural gas exploration into mid-2007 and oil exploitation until near the end of the decade.

We recognize, however, that a key component of our historical success is the recognition that over a business cycle, Zargon's undeveloped land and underdeveloped property inventory must be replenished at reasonable costs to support future sustainable exploration and development activities. We also recognize that although acquisitions are currently competitive and expensive, we work in an environment of ever-changing business cycles and equity markets, and that over time there will be value opportunities available for well capitalized, patient and disciplined industry participants.

2005

OPERATING HIGHLIGHTS

Capital expenditures in 2005 totalled $54.7 million, with $52.3 million allocated to exploration and development activities. Operating highlights included:

- Drilled a 53.5 net well program, with a 93 percent success rate, that delivered 35.3 net natural gas wells and 13.5 net oil wells.
- Total production grew one percent to 8,342 barrels of oil equivalent per day.
- Zargon's 2005 capital investment program replaced production by 106 percent (proved reserves) and 127 percent (proved and probable reserves).
- Proved and probable reserves increased three percent to 26.77 million barrels of oil equivalent. Proved and probable finding, development and acquisition costs ("FD&A Costs") of $14.11 per barrel of oil equivalent (inclusive of the change in future development costs) met our 2005 corporate recycle ratio objective of 2.0 times.

Our large inventory of underdeveloped oil properties and undeveloped natural gas prospective land provides Zargon the resource base to support our sustainable trust initiatives.

2005

FINANCIAL HIGHLIGHTS

Steady production volumes supported by much higher oil and natural gas prices enabled Zargon to achieve record levels of revenue, cash flow, net earnings and distributions in 2005. Financial highlights included:

- Revenue increased by 31 percent to $162.7 million.
- Cash flow from operations increased by 33 percent to $85.0 million.
- Cash flow from operations per diluted unit increased by 33 percent to $4.51.
- Net earnings increased by 71 percent to $35.4 million.
- Net earnings per diluted unit increased by 83 percent to $2.19.
- Cash distributions increased by 46 percent over annualized 2004 levels to $37.4 million.
- Cash distributions per diluted unit increased by 38 percent over prior year annualized levels to $2.32.

ACKNOWLEDGEMENTS

We are grateful for the support of our unitholders and shareholders and our priority is always to enhance the value of their investment. We are thankful for the commitment and support of our staff as we successfully restructured and continue to modify our organization to execute effectively in the sustainable trust format. We also acknowledge with pleasure the support and advice of our Board of Directors. Specifically, we would like to express our heartfelt gratitude for three senior directors, Messrs. B. J. Seaman, H. E. Joudrie and W. J. Whelan who have either retired in 2005 or have expressed their desire to not stand for re-election in 2006. Each of these individuals have served our organization for more than thirteen years and helped nurture Zargon from a small private entity to our current status. We will miss their valuable counsel and wish them well in the years ahead.

Respectfully submitted,

C.H. Hansen
President and Chief Executive Officer
March 13, 2006

Throughout Zargon's history as both a Trust and as an oil and gas junior producer, Zargon has executed a successful business strategy built on the two complementary businesses of the exploration for and development of natural gas reserves, and the exploitation of existing oil reservoirs.

CORE AREAS & BUSINESS STRATEGIES

Essentially all of Zargon's activities are focused in three core areas with the Alberta Plains and West Central Alberta core areas providing the base for Zargon's natural gas exploration and development business; and the Williston Basin core area in Saskatchewan, Manitoba and North Dakota providing the foundation for Zargon's oil exploitation business. Each of these businesses, while having common elements, also have distinct characteristics.

NATURAL GAS EXPLORATION AND DEVELOPMENT BUSINESS

Zargon's natural gas exploration and development business is built on two property types:

- The Alberta Plains properties are generally more mature gas producing areas. These areas provide the majority of the Trust's natural gas production and reserves. This existing production is predominantly high working interest, operated and produced into trust owned production infrastructure. In 2005, Zargon was able to maintain its Alberta Plains production volumes at essentially the same levels as 2004 while re-investing back into the area only 42 percent of the core area's cash flow.

- The West Central Alberta properties tend to be gas prone areas that are less mature from a development perspective and more exploratory in nature. These West Central Alberta properties are focused in three specific areas, where Zargon has accumulated a considerable undeveloped land position. In 2005, Zargon reinvested 85 percent of the core area's cash flow and delivered successful drilling programs in each of the Pembina, Highvale and Peace River Arch properties of the West Central Alberta core area.

Zargon's natural gas exploration and development activities are based on geophysical and geological analysis to identify and pursue drilling opportunities on the Trust's substantial inventory of undeveloped lands. These undeveloped lands are predominantly situated in large, concentrated land blocks, and for the most part this land is accessible for all season operations.

OIL EXPLOITATION BUSINESS

Zargon's oil business is built on the exploitation of long-life, shallow-decline oil properties that are characterized by large under-exploited volumes of oil-in-place. Zargon's oil prope rties are primarily located in the Williston Basin core area of Southeastern Saskatchewan, Manitoba and immediately across the border in the northern counties of North Dakota. In 2005, Zargon reinvested 53 percent of the cash flow generated from the area and was able to grow volumes by 13 percent. The Trust utilizes reservoir engineering, three-dimensional seismic, horizontal drilling and detailed geological mapping to identify opportunities to increase production and to maximize the ultimate oil recoveries from this large oil-in-place resource base. Frequently, the oil exploitation initiatives include the implementation or modification of waterflood projects.

2005 CORE AREA STATISTICAL SUMMARY

	Alberta Plains	West Central Alberta	Williston Basin	Total
Production (boe/d)	3,783	1,584	2,975	8,342
Production Growth/(Decline) (percent)	1	(13)	13	1
Proved and Probable Reserves (mboe) [1]	9,625	4,036	13,110	26,771
Annual Reserve Growth (percent)	(1)	(4)	8	3
Undeveloped Land (thousand net acres)	120.5	197.7	48.6	366.8
Undeveloped Land Growth (percent)	(17)	7	8	(2)
Core Area Cash Flow ($ million) [2]	45.68	18.57	37.12	101.37
Capital Program ($ million)	19.07	15.77	19.84	54.68
Drilling Program (net wells)	25.1	14.1	14.3	53.5
Three-Year FD&A Costs ($/boe) [3]	12.73	25.98	8.91	13.09

1. *Proved and probable reserves are trust working interest reserves before royalties (6:1).*
2. *The summation of the 2005 core area cash flows are $101.37 million, which compares to the Trust's 2005 cash flow from operations of $84.97 million. The term "core area cash flow" is defined as petroleum and natural gas revenue for a core area, net of royalties and production expenses. The term "cash flow from operations" is defined in the MD&A section of this report. The difference in these cash flows is comprised of the corporate charges including general and administrative costs, interest and financing costs, realized risk management gains/losses, and corporate taxes.*
3. *The reported proved and probable finding, development and acquisition costs ("FD&A") include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and changes in reserve definitions.*

ALBERTA PLAINS

The Alberta Plains core area provides substantial cash flows that are approximately equally allocated to trust distributions and to the necessary reinvestment programs required to maintain stable production volumes.

The Trust's Alberta Plains core area is located in the east central region of Alberta and is made up predominantly of relatively shallow natural gas producing properties. This core area delivered 70 percent of Zargon's total natural gas production in 2005 and contributes large free cash flows that underpin the Trust's monthly distributions. Production volumes have been maintained at a relatively stable level since 2001 through exploration and development drilling programs on the Trust's

ALBERTA PLAINS

Zargon's Alberta Plains core area holds a large undeveloped land inventory that provides the feedstock for exploration and development drilling programs that sustain the area's natural gas production and reserve volumes.

2005

- Shot 130 kilometres of 2D seismic and acquired an additional 219 kilometres of trade seismic data.
- Drilled 25.1 net wells resulting in 22.1 net gas wells, 1.0 net oil well and 2.0 net dry holes.
- Constructed 20.6 net kilometres of pipeline and tied-in 13.9 net gas wells into existing gathering systems.
- Maintained steady core area production with a successful capital reinvestment program amounting to only 42 percent of the area's cash flow.

2006

- Continue to execute the exploration and development strategy utilized over the past five years of shooting seismic, drilling wells and optimizing facilities. Specifically, in 2006, Zargon will focus on reduced spacing development drilling opportunities.
- Drill approximately 19 net wells at the Jarrow, Hamilton Lake, Taber and Ukalta properties.
- Reinvest approximately 50 percent of the core area's cash flow to maintain a stable production base of approximately 3,700 barrels of oil equivalent per day.

ALBERTA PLAINS
Production
(boe/d)

existing land base. In 2005, the Alberta Plains core area generated $45.68 million of property cash flow, of which $19.07 million was reinvested in the core area to maintain production volumes.

During 2005, the Trust concluded a successful capital program focused on drilling, completions and tie-ins. Despite providing more than $26.61 million of core area cash flow in excess of capital expenditures, the area's year end proved and probable reserves stayed relatively steady, declining one percent to 9.63 million barrels of oil equivalent. The core area's production volumes were also essentially flat with 2005 production volumes climbing one percent to 3,783 barrels of oil equivalent per day. Once again, the Alberta Plains capital programs were very efficient in 2005, providing proved and probable reserve additions at a cost of $14.36 per barrel of oil equivalent.

ALBERTA PLAINS

	2005	2004	2003	2002	2001
Average Production					
Oil and liquids (bbl/d)	**553**	595	640	660	716
Natural gas (mmcf/d)	**19.38**	19.02	17.31	17.52	16.45
Equivalents (boe/d)	**3,783**	3,765	3,525	3,580	3,458
Total Proved & Probable Reserves (1)					
Oil and liquids (mbbl)	**1,962**	1,932	1,840	2,065	2,127
Natural gas (bcf)	**46.00**	46.57	44.01	49.74	52.85
Equivalents (mboe)	**9,625**	9,694	9,208	10,355	10,935
Undeveloped Lands					
Net acres (thousands)	**120.5**	146.0	185.4	189.3	173.7
Drilling Activities					
Net wells	**25.1**	21.4	12.8	14.9	40.5

ALBERTA PLAINS (cont'd)

	2005	2004	2003	2002	2001
Capital Expenditures ($ million)					
Net property and corporate acquisitions	**0.03**	0.60	(1.16)	5.20	(4.90)
Undeveloped land, seismic, geological	**2.41**	3.09	3.04	1.48	6.19
Drilling, completion, equipping, facilities	**16.63**	10.88	7.39	5.68	16.86
Total expenditures	**19.07**	14.57	9.27	12.36	18.15
Capital Program Efficiencies					
Finding, development and acquisition costs ($/boe) (2)	**14.36**	7.56	65.03	15.41	21.41

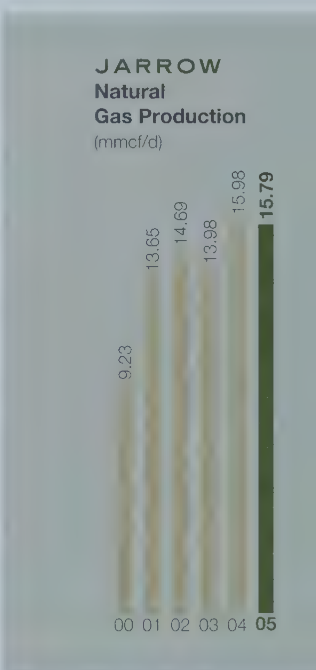
1. Proved and probable reserves are trust working interest reserves before royalties (6:1).

2. The reported proved and probable finding, development and acquisition costs ("FD&A") include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and changes in reserve definitions.

Going forward, Zargon continues to have a large inventory of opportunities that should provide stable Alberta Plains production volumes through 2007. These opportunities include new exploration plus development drilling programs in the following key properties:

JARROW PROPERTY

The Jarrow property continues to be the Trust's most significant producing natural gas property. This property is characterized by high working interests, ownership and operatorship of significant pipeline and gas processing facilities and a continuing large inventory of prospects on an 82 thousand net acre undeveloped land inventory. Although the Jarrow undeveloped land inventory dropped 19 percent from 2004 levels, this decline can be attributed to a significant number of oil and gas leases reaching the end of their five year term. Considerably fewer expiries will occur in 2006 and the Trust anticipates that Jarrow land inventory will remain relatively unchanged in 2006.



Since 2001, Zargon's strategy for Jarrow has been to sustain net natural gas production levels from this property at approximately 15 million cubic feet per day. This strategy attempts to balance, in a sustainable manner, the efficient loading of the existing infrastructure capacity while capitalizing on the considerable inventory of natural gas prospects. In 2006, the Trust will focus on recent down spacing approvals that will facilitate the further development of the large partially drained Ostracod, Glauconite and Colony pools located in the two Jarrow Units.

During the year, Zargon drilled 22.1 net (25 gross) wells at Jarrow, resulting in 20.1 net natural gas wells and 2.0 net dry holes. The Trust also shot 130 kilometres of 2D seismic as part of its ongoing exploration and development programs.

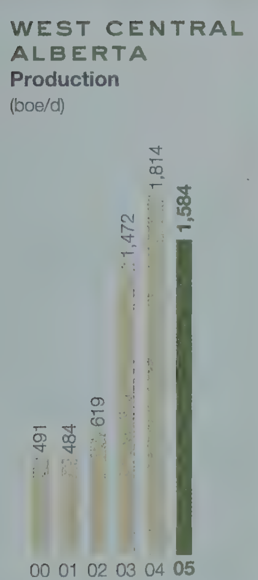
OTHER ALBERTA PLAINS PROPERTIES

Also located in the Alberta Plains core area is the Hamilton Lake property where Zargon produced 2.49 million cubic feet of natural gas per day and 92 barrels of oil and liquids per day in 2005 from the Mannville and Viking formations. The property consists of a mostly contiguous 20 thousand net acre land block that has significant development potential in the lower permeability but extensive first Viking sand formation. In 2006, Zargon plans to confirm the economics of this resource with the drilling of a pilot development program.

Ukalta and Taber are other significant properties included in the Alberta Plains core area. In 2006, Zargon will proceed with development infill programs for both the Ukalta natural gas property and the Taber medium gravity oil property.

WEST CENTRAL ALBERTA

The West Central Alberta core area provides significant cash flows that have been historically reinvested to explore the area's large inventory of undeveloped lands.



Zargon's West Central Alberta core area is located west of Edmonton in central Alberta and is comprised of three natural gas producing regions that provide the Trust with a varied inventory of exploration opportunities. This core area currently delivers approximately 30 percent of Zargon's natural gas production and with exploration success can provide Zargon with the opportunity to grow its natural gas production volumes. In 2005, Zargon spent $15.77 million of capital in the West Central Alberta core area, which represented 85 percent of the $18.57 million of property cash flow generated by the core area. With these expenditures, Zargon drilled 14.1 net wells in this core area that resulted in 13.1 net natural gas wells and 1.0 net dry hole. Following disappointing 2004 exploration results, the smaller 2005 West Central Alberta exploration program was successfully reconfigured to focus on lower risk targets.

Despite encouraging drilling results in the year, the West Central Alberta core area's production declined 13 percent in 2005 to 1,584 barrels of oil equivalent per day. This decline was the direct result of the mid-year production loss of almost three million cubic feet per day of natural gas, when the Trust's previously most prolific well located at Progress on the Peace River Arch watered out.

During the year, the West Central Alberta core area's undeveloped acreage increased by seven percent to 198 thousand net acres. Due to the impact of the 0.66 million barrels of oil equivalent negative reserve revisions coming from the loss of the Progress well, the core area's proved and probable reserves showed a three percent decline to 4.04 million barrels of oil equivalent. The corresponding 2005 finding and development cost for the core area was $38.23 per barrel of oil equivalent. Excluding the impact of this negative Progress reserve adjustment, the year's West Central Alberta drilling program would have delivered a 13 percent increase in proved and probable reserves and a more acceptable finding and development cost of $15.48 per barrel of oil equivalent.

WEST CENTRAL ALBERTA

	2005	2004	2003	2002	2001
Average Production					
Oil and liquids (bbl/d)	**209**	218	260	234	156
Natural gas (mmcf/d)	**8.25**	9.56	7.27	2.31	1.97
Equivalents (boe/d)	**1,584**	1,814	1,472	619	484
Total Proved & Probable Reserves (1)					
Oil and liquids (mbbl)	**455**	499	585	618	488
Natural gas (bcf)	**21.49**	22.00	22.19	18.56	11.61
Equivalents (mboe)	**4,036**	4,166	4,283	3,711	2,423
Undeveloped Lands					
Net acres (thousands)	**197.7**	184.9	173.6	109.1	38.4
Drilling Activities					
Net wells	**14.1**	20.6	17.8	12.8	4.1
Capital Expenditures ($ million)					
Net property and corporate acquisitions	**0.13**	0.40	(2.33)	5.25	0.48
Undeveloped land, seismic, geological	**3.20**	4.77	7.50	4.55	1.20
Drilling, completion, equipping, facilities	**12.44**	16.95	10.38	7.12	2.47
Total expenditures	**15.77**	22.12	15.55	16.92	4.15
Capital Program Efficiencies					
Finding, development and acquisition costs ($/boe) (2)	**38.23**	40.95	13.63	12.50	11.14

1. Proved and probable reserves are trust working interest reserves before royalties (6:1).

2. The reported proved and probable finding, development and acquisition costs ("FD&A") include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and changes in reserve definitions.

Further to a successful West Central Alberta exploration program in the 2005 fourth quarter, Zargon has 12 net wells scheduled to be tied-in during 2006. These tie-ins will provide a steady source of new production volumes to offset naturally occurring production declines for the majority of 2006. The combination of these new wells and a promising inventory of exploration locations should provide both production and reserve growth in 2006 for this core area. Significant exploration opportunities exist in each of the following key properties:

GREATER HIGHVALE

Zargon's 45 thousand net acres of undeveloped land in the Greater Highvale property is centered around a 54 section land block situated on and around Paul First Nation lands located west of Edmonton. Zargon owns and operates natural gas production infrastructure in the area and pursues seismically defined structural prospects at medium depths. The structural geology lends itself to stacked pay with potential for multiple pay zones.

Further to a successful West Central Alberta exploration program in the 2005 fourth quarter, Zargon has 12 net wells scheduled to be tied-in during 2006.

2005

- **Shot 80 kilometres of 2D seismic and acquired an additional 127 kilometres of trade seismic data.**
- **Drilled 14.1 net wells resulting in 13.1 net gas wells and 1.0 net dry hole.**
- **Constructed 2.6 net kilometres of pipeline and tied-in 3.0 net gas wells into existing gathering systems.**

2006

- **Continue to build on the 2005 exploration successes in the Greater Highvale, Pembina and Peace River Arch properties, by building and drilling seismically focused exploration targets. Specifically, drill 17 net natural gas exploration targets.**
- **Tie-in 12 net previously drilled wells plus new wells drilled in the 2006 exploration program.**
- **With a reinvestment of less than 100 percent of the core area's property cash flow, grow production levels to 1,900 barrels of oil equivalent per day by the end of the year.**

Greater Highvale activities in 2005 included the drilling of 3.0 net natural gas wells. In addition, under the terms of an agreement to farmout deeper rights, a third party shot a 12 square kilometre 3D seismic program over Zargon lands.

The Greater Highvale property provided 3.84 million cubic feet per day of natural gas and 200 barrels per day of oil and liquids production to Zargon in 2005. In 2006, three net natural gas exploration wells are planned for the Highvale area.

PEMBINA SHALLOW GAS

Over the last five years Zargon has been pursuing shallow under-pressured Scollard and Horseshoe Canyon sands in the Pembina area at depths up to 900 metres. Zargon has acquired an inventory of 60 thousand acres on this prospect and has constructed a sweet gas gathering and compression facility.

In 2005, Zargon drilled 5.8 net natural gas wells in the Pembina area and the property provided 1.93 million cubic feet per day of production to Zargon's interest. Last year's drilling program successfully focused on higher deliverability targets and with the tie-in of these wells, increased volumes are anticipated in 2006. Zargon is planning to follow up on last year's exploration successes with an expanded seven net well drilling program in 2006.

PEACE RIVER ARCH EXPLORATION

In the Peace River Arch exploration area, Zargon is pursuing multiple zone gas exploration prospects at drilling depths ranging up to 1,800 metres. The Peace River Arch exploration strategy is more "grassroots" than in other areas as the Trust develops prospects, posts land, shoots seismic and drills high graded prospects. Over the last three years, Zargon has built an 86 thousand net acre undeveloped land inventory that is generally characterized by year round surface access and sweet natural gas multi-zone prospects.

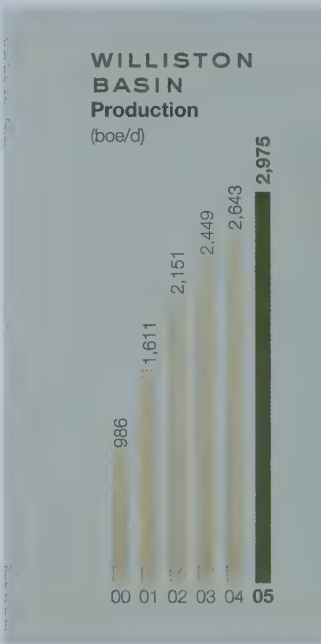
In 2005, the Trust drilled 5.3 net wells in the Peace River Arch area that resulted in 4.3 net natural gas wells and 1.0 net abandonment. Production for the area averaged 2.43 million cubic feet per day of natural gas and eight barrels per day of oil and liquids.

In 2006, Zargon plans to tie-in six Peace River Arch net wells at the Sturgeon Lake, Hamelin Creek, Progress South, Eaglesham and Saddle Hills properties, which should more than replace last year's losses from the watering out of the Progress well. Building on the 2005 exploration successes, an expanded seismically focused drilling program of seven net wells is planned for the Peace River Arch property in 2006.

WILLISTON BASIN

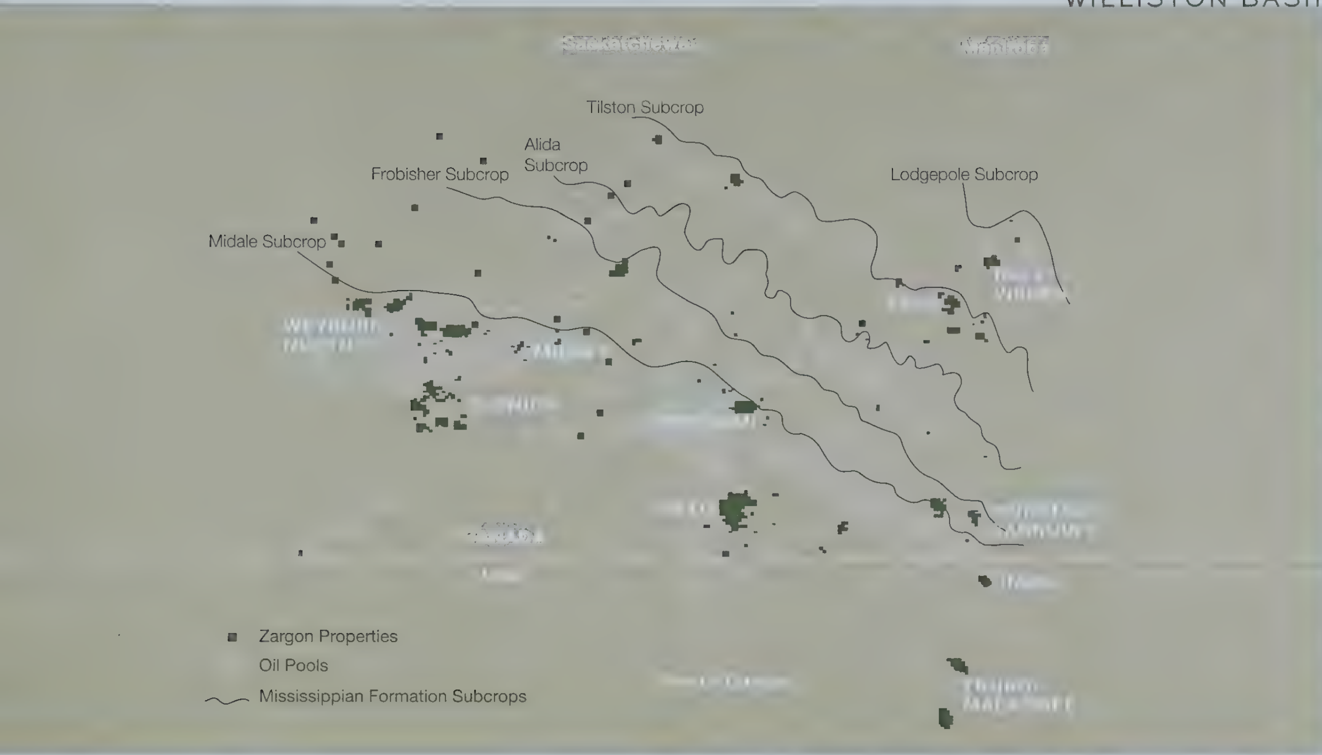
The Williston Basin core area is characterized by a very stable oil production base that offers significant long term exploitation opportunities. The core area provides substantial cash flows that can be allocated to trust distributions or can be reinvested to provide production growth.

The Williston Basin properties are located in relatively close proximity in southeast Saskatchewan, southwest Manitoba and in the northern counties of the State of North Dakota. The properties produce light and medium gravity oil from carbonate reservoirs at depths up to 1,500 metres. The Williston Basin contributes about 80 percent of the Trust's oil and liquids production, 84 percent of the Trust's proved and probable oil and liquids reserves and provides a long proved and probable reserve life of 10.9 years.



Zargon's Williston Basin producing reservoirs are characterized by moderate permeability and a large remaining oil-in-place. By the nature of the physical characteristics of these reservoirs, the properties demonstrate relatively stable production with shallow annual declines and accordingly long reserve life indices.

Through exploitation projects, Zargon attempts to find methods to increase the ultimate oil recoveries from these reservoirs. Generally, Zargon uses a combination of exploitation techniques including pressure maintenance by water injections, three-dimensional seismic and horizontal drilling to unlock additional oil reserves. Frequently, optimizing pressure support in the oil reservoir by water injections is the first step in the exploitation process. With pressure support established, Zargon seeks to characterize the reservoirs through 3D seismic analysis and interpretation, which is followed by horizontal wells designed to increase recoveries and accelerate production.



The following table identifies 20 Williston Basin waterflood exploitation projects that Zargon is currently undertaking:

WILLISTON BASIN OIL EXPLOITATION PROJECTS

	Waterflood Projects	Zargon Working Interest (percent)	WI [1] Oil-in-Place (mmbbl)	WI Cumulative Production (mmbbl)	WI Recovery To Date (percent)	WI [2] Remaining Reserves (mmbbl)	WI Ultimate Recovery (mmbbl)	Ultimate Recovery (percent)
North Dakota								
Haas	1	98	51.2	9.9	19	3.8	13.6	27
Truro/Mackobee	2	100	22.0	2.6	12	1.5	4.1	19
Manitoba								
Daly/Virden	2	100	27.6	3.0	11	1.1	4.2	15
Saskatchewan								
Elswick	3	97	11.1	1.2	11	0.7	1.9	17
Frys	2	100	11.2	1.1	10	0.6	1.7	15
Midale	1	93	7.4	1.0	14	0.3	1.3	18
Pinto	2	100	5.7	0.7	12	0.5	1.2	21
Steelman	2	89	10.5	1.4	13	0.7	2.1	20
Weyburn North	3	76	20.7	2.8	14	1.0	3.8	18
Workman/Carnduff	2	55	8.6	1.3	15	0.4	1.7	20
Total	20		176.0	25.0	14	10.6	35.6	20

1. As estimated by Zargon Energy Trust.

2. Represents 2005 year end remaining proved and probable reserves as estimated by McDaniel & Associates.

These 20 waterflood projects, which represent 81 percent of Zargon's Williston Basin reserves, are in various stages of implementation and are estimated to contain 176 million barrels of oil-in-place attributed to Zargon's working interests. Based on the year end 2005 McDaniel proved and probable reserve assignment, these properties are predicted to recover an average of 20.2 percent of their original oil-in-place, which represents a 0.8 percent recovery factor improvement over the McDaniel 2004 year end estimate. This incremental reservoir recovery factor is directly attributable to Zargon's ongoing exploitation programs. Going forward, Zargon will continue to reinvest considerable time and capital to improve these ultimate recovery factors through a multi-year program of exploitation drilling and waterflood modifications.

In 2005, Zargon drilled 9.5 net horizontal wells and 4.8 net vertical wells in the Williston Basin resulting in 12.6 net oil wells, 0.9 net water injectors and 0.8 net abandonments. The Trust also shot one 3D seismic program at Elswick, Saskatchewan. In 2005, Zargon doubled its field capital program in the Williston Basin over 2004 levels and the Trust is budgeting a similar capital program in 2006. This program will continue to focus on improving waterflood recoveries with the drilling of additional vertical step-outs and injectors plus the drilling of horizontal drainage wells.

In 2005, the Williston Basin area generated $37.12 million of property cash flow of which $19.84 million, or 53 percent, was reinvested in the core area. Through the reinvestment of just over half of the Williston Basin cash flow, the area was able to realize a 13 percent increase in production volumes from 2,643 barrels of oil equivalent per day in 2004 to 2,975 barrels of oil equivalent per day in 2005. This capital program also delivered an eight percent increase in the year end proved and probable reserves to 13.11 million barrels of oil equivalent. The 2005 Williston Basin capital programs were very efficient, providing new proved and probable reserve additions at $8.78 per barrel of oil equivalent with almost half of the incremental reserves coming from technical revisions related to ongoing waterflood programs. In particular, the 2005 horizontal drilling program provided significant wells at the Pinto, Haas and Truro properties, which will be followed up with further development in 2006.

Going forward, Zargon has identified numerous exploitation opportunities that should provide stable production volumes for many years to come with the reinvestment of less than 50 percent of the area's cash flow. Production growth can be anticipated from this core area if additional capital is allocated to these exploitation projects.

Zargon owns a significant inventory of exploitable Williston Basin properties producing from Mississippian carbonate reservoirs characterized by shallow production declines and a large oil-in-place.

2005

[illegible]

- **Drilled 9.5 net horizontal wells and 4.8 net vertical wells resulting in 12.6 net oil wells, 0.9 net water injectors and 0.8 net dry holes.**
- **Shot 4.7 square kilometres of 3D seismic and acquired an additional 254 kilometres of trade seismic data.**
- **Constructed 6.9 net kilometres of pipeline and tied-in 8.6 net oil wells into existing batteries.**
- **Concluded a small corporate acquisition to acquire a complementary property adjacent to Pinto development drilling successes.**

2006

[illegible]

- **Exploit and develop the significant Williston Basin oil-in-place resource base through a continued program of 3D seismic, waterflood modifications and exploitation drilling.**
- **Drill 14 net wells at the Elswick, Pinto, Steelman and Weyburn, Saskatchewan plus the Haas and Truro, North Dakota properties.**
- **Reinvest approximately 50 percent of the core area's cash flow and grow the core area's production volumes to 3,200 barrels of oil equivalent per day.**
- **Seek to acquire additional Williston Basin oil properties with significant oil exploitation potential.**

WILLISTON BASIN

	2005	2004	2003	2002	2001
Average Production					
Oil and liquids (bbl/d)	**2,935**	2,603	2,387	2,074	1,569
Natural gas (mmcf/d)	**0.24**	0.26	0.37	0.46	0.25
Equivalents (boe/d)	**2,975**	2,643	2,449	2,151	1,611
Total Proved & Probable Reserves [1]					
Oil and liquids (mbbl)	**12,942**	11,930	11,105	9,761	9,336
Natural gas (bcf)	**1.01**	0.98	0.86	0.93	0.99
Equivalents (mboe)	**13,110**	12,093	11,248	9,916	9,501
Undeveloped Lands					
Net acres (thousands)	**48.6**	45.1	39.4	32.9	28.6
Drilling Activities					
Net wells	**14.3**	7.5	8.0	3.9	3.1
Capital Expenditures ($ million)					
Net property and corporate acquisitions	**2.26**	10.82	6.10	1.20	28.41
Undeveloped land, seismic, geological	**1.51**	1.24	2.13	0.90	1.49
Drilling, completion, equipping, facilities	**16.07**	7.52	6.86	4.17	2.98
Total expenditures	**19.84**	19.58	15.09	6.27	32.88
Capital Program Efficiencies					
Finding, development and acquisition costs ($/boe) [2]	**8.78**	11.76	6.66	5.21	6.32

1. Proved and probable reserves are trust working interest reserves before royalties (6:1).

2. The reported proved and probable finding, development and acquisition costs ("FD&A") include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and changes in reserve definitions.

ACTIVITY REVIEW

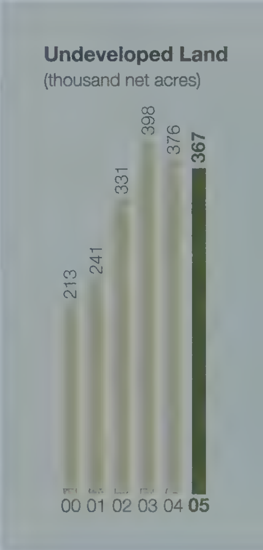
HIGHLIGHTS

Zargon had an active and successful year in 2005, drilling 53.5 net wells, an eight percent increase over the prior year. In addition to supporting Zargon's $2.32 per unit of distributions, this successful drilling program delivered a one percent gain in production and a three percent increase in proved and probable reserves.

	2005	2004	Percent Change
Undeveloped land (thousand net acres)	**367**	376	(2)
Wells drilled, net	**53.5**	49.5	8
Total production (boe/d)	**8,342**	8,222	1
Year end proved and probable reserves (mmboe)	**26.77**	25.95	3

LAND AND SEISMIC

In 2005, Zargon spent $3.65 million on replenishing and maintaining its undeveloped land base. This total was five percent lower than the $3.84 million spent in 2004. During the year, Zargon purchased 31 thousand acres, primarily consisting of natural gas prospective Alberta Crown lands for a total cost of $3.50 million or $113 per acre. Previously, Zargon had acquired 39 thousand net acres in 2004 and 77 thousand net acres in 2003 at average costs of $93 and $81 per acre, respectively. Zargon's higher land costs reflect industry trends to higher Alberta Crown land costs of $253 per acre in 2005, a 74 percent increase over the prior year.



Zargon's undeveloped land inventory decreased two percent in 2005 to 367 thousand net acres. This decline resulted from the combination of a reduced Crown land acquisitions program and by 2005 Alberta Plains expiries. In 2006, Zargon anticipates undeveloped land to decline slightly again as a smaller and more typical level of expiries will be mostly offset by a cautious Crown and freehold acquisitions program during this current period of very high Crown land prices.

The independent firm of Seaton-Jordan & Associates Ltd. ("Seaton-Jordan") has valued Zargon's undeveloped land holdings as of December 31, 2005 at $41.72 million, a 30 percent increase in value over last year's $32.20 million appraisal. This analysis reflects an average value of $114 per acre that compares with the $86 per acre average in 2004.

As part of its continuing exploration effort, Zargon shot 210 kilometres of 2D seismic and 4.7 square kilometres of 3D seismic in 2005. Approximately 130 kilometres of the 2D seismic was shot at the Jarrow property as Zargon continued to assess its considerable inventory of land and natural gas prospect leads in this productive area. Total geological and geophysical costs in 2005 were $3.47 million, which is 34 percent lower than last year's geological and geophysical expenditures of $5.26 million due to a reduced seismic program in the Williston Basin core area.

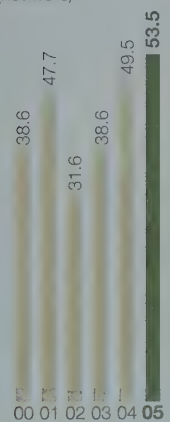
DRILLING, COMPLETIONS AND WORKOVERS

Zargon drilled a total of 53.5 net wells in 2005, an eight percent increase in drilling activity from 2004 and a 39 percent increase from 2003. The 2005 drilling program resulted in 13.5 net oil wells, 35.3 net gas wells, 0.9 net water injectors and 3.8 net dry holes. Zargon's success ratio was 93 percent in the 2005 drilling program, an increase of nine percent from the 85 percent success ratio in 2004.

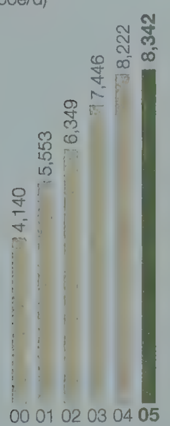
DRILLING ACTIVITY
(Number of Wells)

	2005		2004		2003	
	Gross	**Net**	Gross	Net	Gross	Net
Oil	**15**	**13.5**	7	5.7	11	8.0
Natural Gas	**40**	**35.3**	44	35.4	35	24.6
Water Injector	**1**	**0.9**	1	0.8	–	–
Dry	**4**	**3.8**	8	7.6	6	6.0
Total	**60**	**53.5**	60	49.5	52	38.6
Exploratory	**25**	**23.0**	29	25.9	35	29.4
Development	**35**	**30.5**	31	23.6	17	9.2
Total	**60**	**53.5**	60	49.5	52	38.6
West Central Alberta	**16**	**14.1**	23	20.6	23	17.8
Alberta Plains	**28**	**25.1**	28	21.4	20	12.8
Williston Basin	**16**	**14.3**	9	7.5	9	8.0
Total	**60**	**53.5**	60	49.5	52	38.6
Average Zargon Working Interest		**89%**		83%		74%

Drilling Activity
(net wells)



Production
(boe/d)



During 2005, Zargon operated the drilling of 55 gross wells with an average working interest of 93 percent. Zargon's minor participation in an additional five non-operated wells brought Zargon's average working interest to 89 percent. Similar to recent years, the drilling program was heavily weighted to Alberta natural gas targets with 73 percent of the wells drilled in the Alberta Plains and West Central Alberta natural gas properties compared to 85 percent in 2004. In 2006, Zargon is planning to drill 50 net wells with 36 of these focused on natural gas exploration and development in the Alberta Plains and West Central Alberta, and the remaining on oil exploitation in the Williston Basin.

In 2005, expenditures for drilling, completion and workovers totalled $33.36 million, a 24 percent increase from the $26.94 million spent in 2004. Drilling related expenditures were sharply higher due specifically to Zargon's increased activity levels in the Williston Basin core area and an industry wide trend to higher costs.

PRODUCTION EQUIPMENT AND FACILITIES

In 2005, Zargon spent $11.78 million, a 40 percent increase over the prior year's level, on production equipment and facilities, which included gas plant expansions, oil battery modifications and the construction of approximately 30 net kilometres of pipelines. Approximately 47 percent of these costs were incurred in Alberta Plains, 30 percent in Williston Basin and 23 percent in West Central Alberta core areas.

PROPERTY ACQUISITIONS

Zargon's net property and corporate acquisitions totalled $2.42 million in 2005, significantly lower than the $11.81 million of net property acquisitions completed in 2004. Essentially all of the 2004 and 2005 acquisitions relate to the purchase of oil properties in the Saskatchewan area of the Williston Basin.

PRODUCTION

Natural gas sales volumes decreased three percent in 2005 to average 27.87 million cubic feet per day, compared to 28.84 million cubic feet per day in 2004 (2003 – 24.95 mmcf/d). The decrease in natural gas production was primarily due to the watering out of a significant well in the West Central Alberta core area. Crude oil and natural gas liquid sales volumes increased eight percent in 2005 to 3,697 barrels per day, compared to 3,416 barrels per day in 2004 (2003 – 3,287 bbl/d). These production gains resulted from the oil exploitation drilling program and the 2004 mid-year acquisition of properties in the Williston Basin.

Zargon's 2005 average daily production increased one percent, to 8,342 barrels of oil equivalent per day compared to 8,222 barrels of oil equivalent per day in 2004 (2003 – 7,446 boe/d). On a production per total trust unit basis, Zargon produced 445 barrels of oil equivalent per day per million units in 2005, essentially unchanged from the 2004 levels. During the year, natural gas production represented 56 percent of total volumes, down slightly from a 58 percent weighting in 2004.

RESERVES

Formal disclosure of oil and natural gas reserves as required by National Instrument 51-101 Standards of Disclosure ("NI 51-101") will be included in the Trust's Annual Information Form for the year ended December 31, 2005 that will be filed on SEDAR.

Since 1993, the independent engineering firm of McDaniel & Associates Consultants Ltd. ("McDaniel") has evaluated 100 percent of Zargon's reserves. Commencing with the 2003 year end report, Zargon's reserve estimates have been calculated in accordance with National Instrument 51-101 ("NI 51-101"). Under NI 51-101, proved reserve estimates are defined as having a 90 percent probability that actual reserves recovered over time will equal or exceed proved reserve estimates. Probable reserves are defined under NI 51-101 so that there are equal (50 percent) probabilities that the actual reserves to be recovered will be less than, or greater than, the proved and probable reserves estimate.

In a report dated March 13, 2006, McDaniel assigned the following reserve estimates based on forecast prices and costs as of December 31, 2005:

TRUST RESERVES[1]

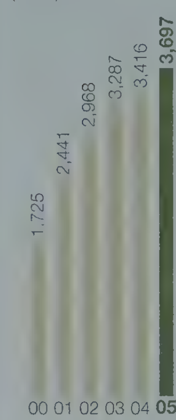
At December 31, 2005	Oil and Liquids (mmbbl)	Natural Gas (bcf)	Equivalents[2] (mmboe)
Proved producing	11.30	34.25	17.00
Proved non-producing	0.19	12.27	2.24
Proved undeveloped	–	–	–
Total proved	**11.49**	**46.52**	**19.24**
Probable additional	3.86	21.98	7.53
Total proved and probable	**15.35**	**68.50**	**26.77**
Proved reserve life index, years	7.8	4.6	6.1
Proved and probable reserve life index, years	10.4	6.8	8.5

1. Trust working interest reserves before royalties, boe (6:1).

2. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In McDaniel's report, proved producing reserves represented 88 percent of Zargon's total proved reserves while total proved reserves accounted for 72 percent of proved plus probable reserves.

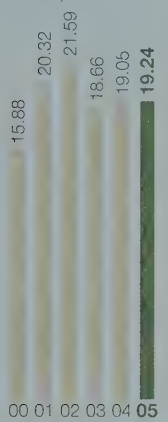
Oil and Liquids Production
(bbl/d)



Natural Gas Production
(mmcf/d)

Production
(boe/d per million trust units)

Proved Reserves
(mmboe)



Proved and Probable Reserves
(mmboe)

Proved and Probable Reserves
(boe/trust unit)

These percentages are relatively unchanged from the respective 89 and 73 percentages reported in the 2004 year end report. Zargon's proved non-producing reserves are comprised primarily of natural gas reserves from recently drilled wells at the West Central Alberta areas of Pembina, Greater Highvale and the Peace River Arch properties and behind pipe natural gas reserves at the Alberta Plains Jarrow property. Zargon has booked no proved undeveloped reserves as at December 31, 2005. McDaniel forecasts $6.88 million of net future (forecast prices) capital costs to deliver the total proved reserve estimate. Zargon's probable reserves generally reflect incremental waterflood recoveries on producing oil properties and improved gas recoveries for currently producing natural gas wells. McDaniel forecasts $8.15 million of net future (forecast prices) capital costs to deliver the total proved and probable reserve estimate.

Based on 2005 year end reserves and Zargon's 2005 fourth quarter production rates of 4,030 barrels of oil and liquids per day and 27.73 million cubic feet of natural gas per day, Zargon's proved reserve life index is 7.8 years for oil and liquids, 4.6 years for natural gas and 6.1 years on an oil equivalent basis. The corresponding proved and probable oil and liquids, natural gas and oil equivalent reserve life indices are 10.4, 6.8 and 8.5 years, respectively. The relatively high oil and liquids reserve life reflects Zargon's portfolio of long-life shallow-decline Williston Basin waterflood projects.

RESERVE RECONCILIATION

A reconciliation of the 2005 year end reserve assignments with the reserves reported in the 2004 year end report is presented below:

RESERVE RECONCILIATION

	Oil and Liquids (mmbbl)			Natural Gas (bcf)			Equivalents (mmboe)		
	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.
December 31, 2004	10.95	3.41	14.36	48.57	20.99	69.56	19.05	6.90	25.95
Discoveries & extensions	0.85	0.48	1.33	8.46	6.12	14.58	2.26	1.50	3.76
Revisions	0.98	(0.04)	0.94	(0.54)	(5.22)	(5.76)	0.89	(0.91)	(0.02)
Acquisitions & dispositions	0.06	0.01	0.07	0.20	0.09	0.29	0.08	0.04	0.12
Production	(1.35)	–	(1.35)	(10.17)	–	(10.17)	(3.04)	–	(3.04)
December 31, 2005	11.49	3.86	15.35	46.52	21.98	68.50	19.24	7.53	26.77

Proved reserves at December 31, 2005 increased one percent from the prior year. Proved 2005 reserve additions were 3.23 million barrels of oil equivalent (after revisions) or 2.34 million barrels of oil equivalent (before revisions). Positive technical reserve revisions were 0.89 million barrels of oil equivalent, which equated to five percent of the 2005 proved reserves opening balance. The majority of the positive revisions were attributed to performance-related adjustments to waterflood oil properties in the Williston Basin offset by negative natural gas revisions due to the watering out of a significant well located at Progress in the Peace River Arch region of the West Central Alberta core area.

On a proved and probable basis, Zargon increased its reserves by three percent in 2005, with the addition of 3.86 million barrels of oil equivalent (after revisions) or 3.88 million barrels of oil equivalent (before revisions), thereby replacing annual production by a factor of 127 percent (128 percent before revisions). Field capital exploration and development programs provided 3.76 million barrels of oil equivalent of new additions, while net acquisitions, primarily in Southeast Saskatchewan, added 0.12 million barrels of oil equivalent additions. Negative technical reserve revisions were 0.02 million barrels of oil equivalent which equated to less than one percent of the 2005 proved and probable reserves opening balance. The majority of the negative technical revisions on a probable basis were due to the watering out of the Progress well. Included in the 2005 capital expenditure program was $7.12 million for undeveloped land and seismic costs that should provide for future reserves additions in subsequent years.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

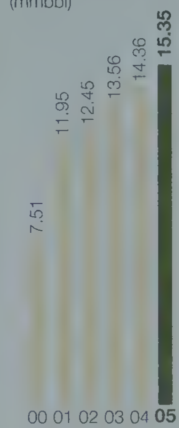
For 2005, Zargon's proved and probable finding, development and acquisition costs ("FD&A costs"), taking into account reserve revisions and changes in estimated future development capital during the period, were $14.11 per barrel of oil equivalent. For the purposes of this calculation, the $54.68 million of 2005 net capital additions were combined with a decrease in estimated future development capital for proved and probable reserves of $0.22 million ($8.15 million at December 31, 2005 compared to $8.37 million at December 31, 2004). If the change in future development costs is excluded, the 2005 proved and probable finding, development and acquisition costs, taking into account reserve revisions, were $14.17 per barrel of oil equivalent.

PROVED AND PROBABLE FINDING, DEVELOPMENT AND ACQUISITION COSTS

	2005	2004	2003
Total net capital expenditures ($ million)	**54.68**	56.27	39.91
Total net capital expenditures plus change in forecast future development costs ($ million)	**54.46**	57.88	39.00
Proved and probable reserves (mmboe) (1)			
Open	**25.95**	24.74	23.98
Discoveries & extensions	**3.76**	2.97	3.71
Acquisitions & dispositions	**0.12**	0.95	0.77
Revisions	**(0.02)**	0.30	(1.00)
Production	**(3.04)**	(3.01)	(2.72)
Close	**26.77**	25.95	24.74
Proved and probable FD&A costs ($/boe) (1)	**14.11**	13.72	11.21
Proved and probable three-year FD&A costs ($/boe) (1)	**13.09**	11.89	9.85

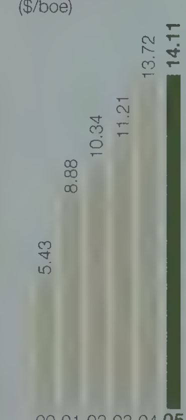
1. Certain comparative numbers reflect the retroactive restatement of removing royalty interest reserves from the Trust interest reserves in accordance with NI 51-101.

Proved and Probable Oil and Liquids Reserves
(mmbbl)



Proved and Probable Natural Gas Reserves
(bcf)

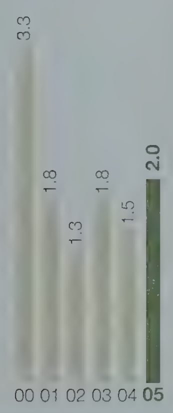
Proved and Probable Finding, Development and Acquisition Costs
($/boe)



Zargon experienced slightly higher FD&A costs in 2005 as the combination of a successful drilling program and positive oil revisions were almost successful in offsetting the negative proved and probable reserve revisions of 4.0 billion cubic feet related to the watering out of a significant West Central Alberta well. Excluding the impact of this write-off, Zargon's 2005 proved and probable FD&A costs would have been a very strong $12.05/boe.

In 2005, Zargon's net acquisitions (including corporate acquisitions) accounted for only four percent of Zargon's total capital expenditures. If the impact of the 2005 net acquisitions and corporate acquisitions is excluded, Zargon's proved and probable finding and development costs ("F&D costs") would have been $13.91/boe (2004 – $14.09/boe).

Proved and Probable Trust Recycle Ratios



CAPITAL PROGRAM PERFORMANCE

	2005	2004	2003	Three-Year Average (2003 – 2005)
Trust cash flow ($/boe)(1)	**27.91**	21.18	20.00	23.15
Total Capital Program				
Proved and probable FD&A costs ($/boe)(2)	**14.11**	13.72	11.21	13.09
Trust recycle ratio(3)	**1.98**	1.54	1.78	1.77
Production addition cost ($/thousand/boe/d)(4)	**35.30**	37.63	29.21	34.04
Capital Program Exclusive of Net Property Acquisitions and Corporate Acquisitions				
Proved and probable F&D costs ($/boe)(2)	**13.91**	14.09	13.43	13.84
Trust recycle ratio(3)	**2.01**	1.50	1.49	1.67
Production addition costs ($ thousand/boe/d)(4)	**33.50**	29.37	27.04	29.97

1. Trust cash flow from operations including allowances for current taxes, interest charges and general and administrative costs on a barrel of oil equivalent production basis (6:1).

2. FD&A and F&D costs taking into account reserve revisions and changes in estimated future development capital during the period on a barrel of oil equivalent basis (6:1).

3. Trust recycle ratio is defined as the trust cash flow from operations per barrel of oil equivalent divided by proved and probable finding, development and acquisition costs per barrel of oil equivalent. In the case of amounts for the capital program exclusive of net acquisitions and corporate acquisitions, the trust cash flow per barrel of oil equivalent is divided by proved and probable finding and development costs.

4. The production addition costs for the total capital program are calculated by dividing the year's total capital expenditures by the year's actual change in production rate plus the year's estimated naturally occurring decline in production. This production decline is estimated as the year end proved producing (forecast case) depletion rate (the inverse of the reserve life index) based on fourth quarter production rates. The production addition costs for the capital program exclusive of net acquisitions and corporate acquisitions are calculated on a similar basis except total capital, reserves and production are adjusted for the amounts related to net acquisitions and corporate acquisitions.

5. Certain comparative numbers reflect the retroactive restatement of removing royalty interest reserves from the Trust interest reserves in accordance with NI 51-101.

A key element of Zargon's sustainability strategy requires Zargon to deliver a two times proved and probable recycle ratio through its exploration and development programs (total capital program except for net acquisitions). In 2005, Zargon successfully met this objective.

NET ASSET VALUE

Zargon's oil, natural gas liquids and natural gas reserves were evaluated using McDaniel product price forecasts effective January 1, 2006, prior to provisions for income taxes, interest, debt service charges and general and administrative expenses. It should not be assumed that the following discounted future net property cash flows estimated by McDaniel represent the fair market value of the reserves:

BEFORE TAX PRESENT VALUE OF FUTURE NET REVENUE
(Forecast Price Case)

	Discount Factor			
($ million)	0%	5%	10%	15%
Proved producing	417.9	346.3	298.4	264.6
Proved non-producing	66.3	59.2	53.5	48.8
Proved undeveloped	–	–	–	–
Total proved	**484.2**	**405.5**	**351.9**	**313.4**
Probable	207.5	135.9	99.5	78.4
Total proved and probable	**691.7**	**541.4**	**451.4**	**391.8**

BEFORE TAX PRESENT VALUE OF FUTURE NET REVENUE
(Constant Price Case)

	Discount Factor			
($ million)	0%	5%	10%	15%
Proved producing	488.5	391.1	329.2	286.5
Proved non-producing	81.1	70.7	62.7	56.3
Proved undeveloped	–	–	–	–
Total proved	**569.6**	**461.8**	**391.9**	**342.8**
Probable	248.2	164.2	120.6	94.6
Total proved and probable	**817.8**	**626.0**	**512.5**	**437.4**

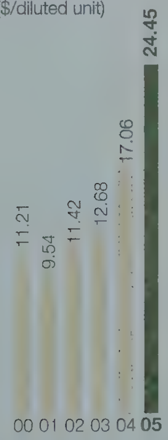
The above discounted future net property cash flows are based on the McDaniel price assumptions that are contained in the following table.

McDANIEL REPORT PRICING ASSUMPTIONS
(Forecast and Constant Price Cases)

	WTI Crude Oil ($US/bbl)	Edm. Par Price ($Cdn/bbl)	Cromer Med. ($Cdn/bbl)	AECO Gas Price ($Cdn/gj)	Exchange Rate ($US/$Cdn)	Inflation Rate (percent)
Forecast Prices						
2006	57.50	66.60	58.50	10.05	0.85	2.5
2007	55.40	64.20	56.30	9.05	0.85	2.5
2008	52.50	60.70	53.30	8.05	0.85	2.5
2009	49.50	57.20	50.20	7.00	0.85	2.5
2010	46.90	54.10	47.50	6.55	0.85	2.5
2011	48.10	55.50	48.70	6.75	0.85	2.5
Thereafter:	Escalate at 2.5%/year	Escalate at 2.5%/year	Escalate at 2.5%/year	Escalate at 2.5%/year	0.85	2.5
Constant Prices						
2005 year end	61.04	68.46	51.65	9.29	0.85	–

The following net asset value table shows what is customarily referred to as a "produce-out" net asset value calculation under which the current value of Zargon's reserves would be produced at McDaniel forecast future prices and costs. The value is a snapshot in time as of December 31, 2005 and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. In this analysis, the present value of the proved and probable reserves is calculated at a before tax 10 percent discount rate, and the value assigned to the undeveloped land was provided by the independent firm of Seaton-Jordan & Associates Ltd.

Net Asset Value (PVBT 10%)
($/diluted unit)



NET ASSET VALUE

As at December 31 ($ million)	**2005**	2004	2003
Proved and probable reserves (PVBT 10%)[(1)(2)]	**451.4**	308.2	219.6
Undeveloped land [(3)]	**41.7**	32.2	29.0
Working capital (excluding unrealized risk management liability)	**(17.1)**	(9.1)	(6.1)
Bank debt	**(10.3)**	(14.2)	(7.0)
Proceeds from the exercise of all trust unit rights	**20.9**	10.3	9.1
Net asset value (including trust unit rights dilution)	**486.6**	327.4	244.6
Net asset value per unit			
Total ($/unit)	**24.53**	17.04	13.09
With full dilution ($/unit)[(4)]	**24.45**	17.06	12.68

1. *McDaniel's estimate of future before tax cash flow discounted at PV 10 percent.*
2. *PVBT represents present value before taxes.*
3. *Seaton-Jordan year end estimates.*
4. *Full dilution of units represent the year end units outstanding plus the presumed exercise of all trust unit rights and the conversion of exchangeable shares converted at the exchange ratio at the end of the period.*

If the net asset value calculation is adjusted to assume that the commodity prices received at year end 2005 (Edmonton light crude oil at $68.46 Cdn per barrel and Alberta AECO average natural gas at $9.29 Cdn per gj) will remain constant throughout the future (McDaniel constant price case), the equivalent analysis calculates a 10 percent present value before tax (PVBT) net asset value of $27.52 per fully diluted unit.

TRUST SUSTAINABILITY

With the conversion during 2004 to a trust, Zargon's objectives are to sustain distributions, production and reserves on a per unit basis after paying out approximately 50 percent of cash flow attributable to unitholders. The following is a summary of the key metrics that Zargon monitors as it works towards meeting its sustainability objectives:

KEY SUSTAINABILITY METRICS

	2005	2004	Percent Change
Annualized cash distributions ($/unit)	**2.32**	1.68	38
Cash flow from operations ($/unit diluted)	**4.51**	3.40	33
Trust payout ratio (percent)	**51**	49	4
Production (boe/d per million units)	**445**	447	–
Proved and probable reserves (boe/total unit)	**1.41**	1.39	1
Cash flow from operations ($/boe)	**27.91**	21.18	32
Proved and probable FD&A costs ($/boe)	**14.11**	13.72	3
Trust recycle ratio	**1.98**	1.54	29
Production addition costs ($ thousand/boe/d)[1]	**35.3**	37.6	(6)

1. The production addition costs for the total capital program are calculated by dividing the year's total capital expenditures by the year's actual change in production rate plus the year's estimated naturally occurring decline in production. This production decline is estimated as the year end proved producing (forecast case) depletion rate (the inverse of the reserve life index) based on fourth quarter production rates.

In early 2006, Zargon reached a significant milestone. Over its thirteen-year history, Zargon has raised approximately $50 million in equity (includes equity issued for all public and private offerings, for property acquisitions and for the exercise of employee stock options or trust unit rights). With the distribution declared on February 15, 2006, Zargon has paid back this entire amount by distributing $54 million to its unitholders.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis (MD&A) is a review of Zargon Energy Trust's 2005 financial results and should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2005 and 2004. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are in Canadian dollars unless otherwise noted. All references to "Zargon" or the "Trust" refer to Zargon Energy Trust and all references to the "Company" refer to Zargon Oil & Gas Ltd.

In the MD&A, reserves and production are commonly stated in barrels of oil equivalent (boe) on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil (boe). Boes may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalent conversion method primarily applicable to the burner tip and does not represent a value equivalent at the wellhead.

The following are descriptions of non-GAAP measures used in this MD&A:

- *The MD&A contains the term "cash flow from operations" ("cash flow"), which should not be considered an alternative to, or more meaningful than, "cash flow from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Trust's financial performance. This term does not have any standardized meaning as prescribed by GAAP and therefore, the Trust's determination of cash flow from operations may not be comparable to that reported by other trusts. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows in the consolidated financial statements. The Trust evaluates its performance based on net earnings and cash flow from operations. The Trust considers cash flow from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt and to fund future capital investment. It is also used by research analysts to value and compare oil and gas trusts, and it is frequently included in published research when providing investment recommendations. Cash flow from operations per unit is calculated using the diluted weighted average number of units for the period.*

- *Payout ratio equals distributions as a percentage of cash flow for the period. Payout ratio is a useful measure used by management to analyze the Trust's efficiency and sustainability.*

- *The Trust also uses the term "debt net of working capital". Debt net of working capital as presented does not have any standardized meaning prescribed by Canadian GAAP and may not be comparable with the calculation of similar measures for other entities. Debt net of working capital as used by the Trust is calculated as bank debt and any working capital deficit excluding the current portion of unrealized risk management assets or liabilities.*

- *Operating netbacks equal total petroleum and natural gas revenue per boe less realized risk management losses per boe, royalties per boe, and production costs per boe. Operating netbacks are a useful measure to compare the Trust's operations with those of its peers.*

- *Cash flow netbacks per boe are calculated as operating netbacks less general and administrative expenses per boe, interest and financing charges per boe, and capital and current income taxes per boe. Cash flow netbacks are a useful measure to compare the Trust's operations with those of its peers.*

References to "production volumes" or "production" in this MD&A refer to sales volumes.

Forward-Looking Statements: This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this MD&A are as of March 13, 2006 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

This MD&A has been prepared as of March 13, 2006.

PLAN OF ARRANGEMENT

On July 15, 2004, approval was given by the shareholders to a resolution in favour of a Plan of Arrangement (the "Arrangement") reorganizing Zargon Oil & Gas Ltd. (the "Company") into Zargon Energy Trust (the "Trust" or "Zargon"). The Arrangement received court approval and also became effective on July 15, 2004. The Arrangement resulted in shareholders of the Company receiving either one trust unit or one exchangeable share for each common share held. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust. Holders of exchangeable shares are not eligible to receive distributions, but rather, on each payment of a distribution, the number of trust units into which each exchangeable share is exchangeable is increased on a cumulative basis in respect of the distribution. The exchangeable shares are traded on the Toronto Stock Exchange and can be converted, at the option of the holder, into trust units at any time. On July 15, 2014, all the remaining outstanding exchangeable shares will be redeemed into trust units unless the Board of Directors of the Company elect to extend the redemption period. In certain circumstances, the Company has the right to require redemption of the exchangeable shares prior to July 15, 2014. Upon completion of the Arrangement, 14.87 million trust units and 3.66 million exchangeable shares were issued. The Trust is an unincorporated open-end investment trust governed by the laws of the Province of Alberta. On September 15, 2004, Zargon commenced cash distributions, relating to August 2004, of $0.14 per trust unit.

The reorganization of the Company into a Trust has been accounted for using the continuity of interest method. Accordingly, the consolidated financial statements for the years ended December 31, 2005 and 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business of the Company. All comparative figures referred to in the consolidated financial statements and this MD&A are the previous consolidated results of the Company.

CASH DISTRIBUTIONS

Cash distributions to unitholders are at the discretion of the Board of Directors and can fluctuate depending on cash flow. The Trust currently targets a payout ratio of approximately 50 percent of the cash flows attributed to unitholders. The Trust's capital program is financed from available cash flow and additional drawdowns on the bank facility if required. The key drivers of Zargon's cash flow are commodity prices and production. Since the Trust's production is relatively evenly weighted between natural gas (2005 – 56 percent) and oil and liquids (2005 – 44 percent), both commodity prices have a significant effect on its cash flow. In the event that oil and natural gas prices are higher than anticipated and a cash surplus develops, the surplus may be used to increase distributions, reduce debt, and/or increase the capital program. In the event that oil and natural gas prices and/or production are lower than expected, the Trust may decrease distributions, increase debt or decrease the capital program. Zargon regularly reviews its distribution policy in the context of the current commodity price environment and production levels.

Distributions remained constant throughout the first seven months of 2005 at $0.14 per unit per month and had been at that level since the Trust's inception in July 2004. On August 11, 2005, Zargon announced its monthly distribution rate would be increased to $0.16 per unit, representing a $0.02 per unit increase. Furthermore, on November 14, 2005 Zargon announced its monthly distribution rate would be increased an additional $0.02 per unit to $0.18 per unit. Other than a supplemental distribution (over-and-above the monthly distribution) declared in December 2005 of $0.50 per unit, distributions have been maintained at the $0.18 per unit level since that date.

Cash distributions to unitholders declared for 2005 totalled $37.44 million, resulting in a payout ratio for the year of 44 percent of cash flow from operations or 51 percent on a per diluted trust unit basis.

For Canadian income tax purposes, the 2005 cash distributions are 100 percent taxable income to unitholders.

2005 HIGHLIGHTS

The combination of high crude oil prices, natural gas prices, and stable production volumes enabled Zargon to achieve record revenues and cash flow from operations in 2005, showing gains of 31 percent and 33 percent, respectively, over the prior year. The annual revenue gain came from a combination of factors, including a 26 percent increase in oil and liquids prices, an eight percent increase in oil and liquids production, and a 32 percent increase in natural gas prices which more than offset the three percent decline in natural gas production. Net earnings for the year were $35.37 million, a 71 percent increase from 2004. Earnings for 2005 were primarily enhanced by record cash flows from operations of $84.97 million, an increase of $21.22 million from 2004, while 2004 earnings were negatively impacted by a significant one-time charge of $2.17 million related to the accelerated vesting of stock options as a result of the July 15, 2004 Arrangement.

Net capital expenditures for 2005 totalled $54.68 million with $52.26 million allocated to field-related activities. Compared to the prior year, the 2005 capital program showed a three percent decline in overall net expenditures and an 18 percent increase in field-related expenditures. Net property acquisitions of $1.23 million were lower in 2005 when compared to the 2004 net property acquisitions of $11.81 million which primarily consisted of a portfolio of oil properties in Weyburn and Elswick, Saskatchewan of the Williston Basin. The 2005 capital expenditures were complemented with the corporate acquisition of a small private Saskatchewan oil and gas company for consideration of $1.19 million. For the year ended December 31, 2005, Zargon spent $3.65 million to maintain an undeveloped land base of 367,000 net acres (2004 – 376,000 net acres); shot or acquired seismic at a cost of $3.47 million; drilled, equipped and tied-in wells for $45.14 million and made net property acquisitions of $1.23 million. Cash distributions to unitholders totalled $37.44 million during the year (2004 – $10.70 million). All of these activities were funded by the high cash flows received throughout the year plus an increase in debt net of working capital (excluding the unrealized risk management liability) of $4.12 million.

FINANCIAL HIGHLIGHTS

($ million, except per unit amounts)	**2005**	2004	2003
Petroleum and natural gas revenue	**162.72**	123.97	101.66
Cash flow from operations	**84.97**	63.75	54.35
Per unit – diluted	**4.51**	3.40	2.96
Net earnings [1]	**35.37**	20.63	24.36
Per unit – diluted [1]	**2.19**	1.20	1.33
Total assets [1]	**277.86**	226.96	181.05
Net capital expenditures [2]	**54.68**	56.27	39.91
Bank debt	**10.34**	14.23	6.98
Cash distributions	**37.44**	10.70	–

1. Comparative 2003 period numbers reflect the retroactive restatements due to a change in accounting policy.

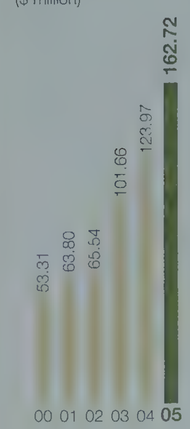
2. Amounts include capital expenditures acquired for cash and equity issuances.

DETAILED FINANCIAL ANALYSIS

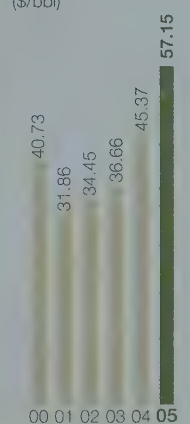
PETROLEUM AND NATURAL GAS REVENUE

Zargon derives its revenue from the production and sale of petroleum (oil, natural gas liquids) and natural gas. Petroleum and natural gas revenue, exclusive of risk management losses, increased 31 percent to $162.72 million in 2005 from $123.97 million in 2004 primarily due to higher prices and a slight increase in production. Compared to the prior year, the allocation of production revenue in 2005 was essentially unchanged with 47 percent of the revenues coming from the sale of oil and liquids (46 percent in 2004) and 53 percent coming from the sale of natural gas (54 percent in 2004). Production volumes on a barrel of oil equivalent basis in 2005 increased one percent to 8,342 barrels of oil equivalent per day from the prior year amounts of 8,222 barrels of oil equivalent per day. Specifically, in 2005 natural gas production decreased three percent and oil and liquids production increased eight percent over 2004 levels. Production increases in oil and liquids resulted from mid-2004 Williston Basin property acquisitions and field exploitation programs. Natural gas production declines resulted primarily from production losses at a significant well in the West Central Alberta core area in mid-2005. The average price of oil and liquids received by Zargon rose to $57.15 per barrel in 2005, up 26 percent from 2004. The average field price of natural gas was $8.41 per thousand cubic feet in 2005, a 32 percent increase over $6.37 per thousand cubic feet in 2004.

Petroleum and Natural Gas Revenue
($ million)



Oil and Liquids Prices
($/bbl)



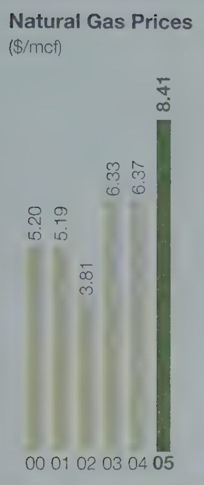
PRICING

Average for the year	**2005**	2004	2003
Natural Gas:			
NYMEX average daily spot price ($US/mmbtu)	**8.89**	5.90	5.49
AECO average daily spot price ($Cdn/mmbtu)	**8.77**	6.55	6.70
Realized price ($Cdn/mcf) (1)	**8.41**	6.37	6.33
Crude Oil:			
WTI ($US/bbl)	**56.56**	41.40	31.04
Edmonton par price ($Cdn/bbl)	**68.72**	52.54	43.14
Realized price ($Cdn/bbl) (1)	**57.15**	45.37	36.66

1. Amounts are before risk management losses.

PETROLEUM (OIL AND NATURAL GAS LIQUIDS) PRICING

Zargon's field oil and natural gas liquids prices are adjusted at the point of sale for transportation charges and oil quality differentials from an Edmonton light sweet crude price that varies with world commodity prices. In 2005, Zargon's average oil and liquids field price, exclusive of risk management losses, rose 26 percent to $57.15 per barrel from $45.37 per barrel in 2004 and $36.66 per barrel in 2003. The field price differential for Zargon's average blended 30 degree API crude stream was $11.57 per barrel less than the 2005 Edmonton reference crude price, which compares to the 2004 differential of $7.17 per barrel and the 2003 differential of $6.48 per barrel. As the quality and weight of Zargon's crude stream have remained relatively consistent for several years, the movements in the Zargon's price differential is derived from the North American refinery supply and demand factors for light and medium crudes.



NATURAL GAS PRICING

The average field natural gas price, exclusive of risk management losses, for 2005 increased to \$8.41 per thousand cubic feet which is 32 percent higher than the 2004 average of \$6.37 per thousand cubic feet, and also 33 percent higher than the 2003 average of \$6.33 per thousand cubic feet. Historically, Zargon's field prices have shown a small discount to the benchmark AECO average daily price (\$0.36 per thousand cubic feet in 2005), due to a lower heating content for Zargon's natural gas and due to legacy aggregator and other contracts which are partially based on monthly index prices that tend to lag the AECO average daily index price in upward trending markets. Zargon is also committed to various fixed price physical contracts which are treated as part of natural gas production revenue and natural gas pricing. In 2005, the physical contracts created a gain of \$0.18 million (2004 – \$0.25 million), equivalent to an increase of \$0.02 per thousand cubic feet, unchanged from 2004.

Similar to the prior year, approximately 23 percent of Zargon's 2005 natural gas production was sold under aggregator contracts pursuant to long term contracts. The remainder of Zargon's natural gas production was sold by spot sale contracts and Alberta index prices were received.

RISK MANAGEMENT ACTIVITIES

Zargon's commodity price risk management policy uses forward sales, puts and costless collars for 20 to 35 percent of oil and natural gas working interest production in order to partially offset the effects of large price fluctuations. As both Canadian oil and natural gas field prices are closely correlated to US dollar denominated markets, Zargon will also place US/Cdn currency exchange risk management transactions when considered prudent. Because our risk management strategy is protective in nature and is designed to guard the Trust against extreme effects on cash flow from sudden falls in prices and revenues, upward price spikes tend to produce overall losses. Financial risk management contracts in place as at December 31, 2004, were designated as hedges for accounting purposes and the Trust continues to monitor these contracts in determining the continuation of hedge effectiveness. For these contracts, realized gains and losses are recorded in the statement of earnings as the contracts settle and no unrealized gain or loss is recognized.

For 2005, the total realized risk management loss was \$7.75 million compared to a loss of \$4.57 million in 2004 and a loss of \$2.88 million in 2003. Of the 2005 loss, \$5.17 million (equivalent to a reduction of \$3.83 per barrel) is related to oil risk management transactions and \$2.58 million (equivalent to a reduction of \$0.25 per thousand cubic feet) was related to natural gas risk management transactions. Oil swaps and collars are settled against the NYMEX pricing index, whereas natural gas swaps, collars, and puts are settled against the AECO pricing index. In 2005, NYMEX WTI crude oil prices increased throughout the year, peaking in the month of September. AECO daily natural gas prices also trended upwards during the year and became volatile towards year end. For financial risk management contracts entered into after December 31, 2004, the Trust does consider these contracts to be an effective hedge on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and accordingly, for outstanding contracts not designated as hedges, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at the period end. The unrealized losses as at December 31, 2005 were \$3.76 million (2004 – nil). These instruments have been recorded as a liability in the consolidated balance sheet. Gains or losses on fixed price physical contracts are included in petroleum and natural gas revenue in the statement of earnings.

 As at December 31, 2005, the Trust had the following outstanding commodity price risk management contracts:

FINANCIAL CONTRACTS DESIGNATED AS HEDGES

	Rate	Price	Range of Terms
Oil collar	200 bbl/d	$36.00 US/bbl Put; $48.40 US/bbl Call	Jan. 1/06 – Jun. 30/06
Natural gas collar	3,000 gj/d	$5.90/gj Put; $10.00/gj Call	Jan. 1/06 – Mar. 31/06

FINANCIAL CONTRACTS NOT DESIGNATED AS HEDGES

	Rate	Price	Range of Terms
Oil swaps	200 bbl/d	$48.50 US/bbl	Jan. 1/06 – Jun. 30/06
	300 bbl/d	$51.83 US/bbl	Jan. 1/06 – Dec. 31/06
	200 bbl/d	$51.12 US/bbl	Jul. 1/06 – Dec. 31/06
Oil collars	200 bbl/d	$40.00 US/bbl Put; $49.05 US/bbl Call	Jan. 1/06 – Jun. 30/06
	200 bbl/d	$52.00 US/bbl Put; $78.95 US/bbl Call	Jan. 1/06 – Dec. 31/06
	200 bbl/d	$55.00 US/bbl Put; $78.05 US/bbl Call	Jul. 1/06 – Dec. 31/06
Natural gas swaps	1,000 gj/d	$12.82/gj	Jan. 1/06 – Mar. 31/06
	4,000 gj/d	$9.31/gj	Apr. 1/06 – Oct. 31/06
Natural gas collars	2,000 gj/d	$6.50/gj Put; $8.80/gj Call	Jan. 1/06 – Mar. 31/06
	2,000 gj/d	$7.00/gj Put; $9.35/gj Call	Jan. 1/06 – Mar. 31/06
	1,000 gj/d	$9.50/gj Put; $12.50/gj Call	Nov. 1/06 – Mar. 31/07
	1,000 gj/d	$10.50/gj Put; $13.18/gj Call	Nov. 1/06 – Mar. 31/07

PHYSICAL CONTRACTS

	Rate	Price	Range of Terms
Natural gas fixed price	4,000 gj/d	$7.92/gj	Apr. 1/06 – Oct. 31/06
Natural gas collars	1,000 gj/d	$8.47/gj Put; $9.50/gj Call	Jan. 1/06 – Mar. 31/06
	1,000 gj/d	$8.50/gj Put; $12.85/gj Call	Nov. 1/06 – Mar. 31/07
	1,000 gj/d	$9.50/gj Put; $13.50/gj Call	Nov. 1/06 – Mar. 31/07

ROYALTIES

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties also include credits received through the Alberta Royalty Credit (ARC) program, the cost of the Saskatchewan Resource Surcharge (SRC) and the cost of North Dakota state taxes. During 2005, total royalties were $37.32 million, an increase of 33 percent from $28.05 million in 2004. Royalties as a percentage of gross revenue were 22.9 percent in 2005 compared to 22.6 percent in 2004 and 22.1 percent in 2003. On a commodity basis, oil royalties averaged 22.5 percent in 2005, a small increase from the previous year's average of 21.5 percent. Natural gas royalties averaged 23.3 percent, relatively unchanged from the prior year.

During 2005, 61 percent of the total royalties were paid to provincial and state governments, with the remainder paid to freehold owners and other third parties. Royalties payable to the Province of Alberta on qualifying properties are reduced through the ARC program. Zargon earned the maximum $0.50 million ARC rebate in 2005, which is the same amount received in both 2004 and 2003. The SRC charges were $1.03 million in 2005, up from $0.64 million in the prior year and $0.53 million in 2003 trending the increase in Saskatchewan oil revenues. North Dakota state taxes increased to $1.82 million in 2005 from $1.25 million in the prior year, primarily due to increased prices for oil, as well as increased production in the state.

PRODUCTION EXPENSES

Zargon's production expenses increased 11 percent to $24.04 million in 2005, from $21.69 million in 2004. On a unit of production basis, production expenses increased nine percent to $7.89 per barrel of oil equivalent from $7.21 in 2004 ($6.33 in 2003).

Natural gas production expenses in 2005 rose 13 percent to $0.95 per thousand cubic feet from $0.84 per thousand cubic feet in 2004. The primary reasons for the increases are due to increased gas gathering charges, increased rentals for compression equipment, increased water disposal and water hauling, all part of the industry-wide trend towards higher operating costs.

Oil production expenses also rose in 2005 to $10.64 per barrel, an increase of three percent from $10.30 per barrel in 2004. With the strong oil prices during the year, there is an industry-wide trend to higher operating costs, particularly for chemicals, propane and equipment repairs.

Due to the high levels of industry activity caused by the high commodity price environment, there is increasing upward pressure on per unit operating costs. In 2003, Zargon was able to deliver a cost improvement on a per unit of production basis over the prior year through the disposition of smaller, higher cost properties. In 2005 and 2004, Zargon's costs increased substantially due in general to the effect of industry-wide higher cost trends. For 2006, Zargon expects the trend of increasing costs to persist as the current high demand for industry services is expected to continue.

OPERATING NETBACKS

The average oil and liquids price received after realized risk management losses in 2005 of $53.32 per barrel was 26 percent higher than the $42.17 per barrel received in 2004, while the average natural gas price received after realized risk management losses in 2005 of $8.16 per thousand cubic feet was 29 percent above the $6.32 per thousand cubic feet received in 2004. Operating netbacks increased commensurately. Oil and natural gas liquids netbacks rose 35 percent to $29.80 per barrel from $22.10 per barrel in 2004. Natural gas netbacks increased 32 percent to $5.25 per thousand cubic feet from $3.98 per thousand cubic feet in 2004. On a barrel of oil equivalent basis, 2005 operating netbacks rose 33 percent to $30.75 from $23.15 in 2004.

OPERATING NETBACKS

	2005		2004	
	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)
Production revenue	**57.15**	**8.41**	45.37	6.37
Realized risk management loss	**(3.83)**	**(0.25)**	(3.20)	(0.05)
Royalties	**(12.88)**	**(1.96)**	(9.77)	(1.50)
Production costs	**(10.64)**	**(0.95)**	(10.30)	(0.84)
Operating netbacks	**29.80**	**5.25**	22.10	3.98

GENERAL AND ADMINISTRATIVE EXPENSES

Gross general and administrative costs increased 24 percent in 2005 to $8.96 million from $7.23 million in 2004. On a unit of production basis, net general and administrative costs increased 37 percent to $1.99 per barrel of oil equivalent, compared to $1.45 per barrel in 2004 and $1.30 per barrel in 2003. In 2005, as was the case in 2004, the increased general and administrative costs on a per unit of production basis were due to increased staff costs, performance-based compensation costs, increased regulatory reporting requirements and the additional legal and other outside advisory costs of operating as a trust.

GENERAL AND ADMINISTRATIVE EXPENSES

($ million, except as noted)	2005	2004	2003
Gross general and administrative expenses	**8.96**	7.23	5.94
Overhead recoveries	**(2.91)**	(2.87)	(2.40)
Net general and administrative expenses	**6.05**	4.36	3.54
Net expense after recoveries ($/boe)	**1.99**	1.45	1.30
Number of office employees at year end	**39**	35	34

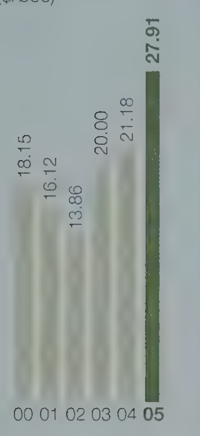
INTEREST AND FINANCING CHARGES

Zargon's borrowings are through its syndicated bank credit facility. Interest and financing charges were $0.79 million compared to $0.44 million in 2004. An increase in the average debt level is the primary reason for the increase in interest and financing charges. Zargon's effective interest and financing charge rate was 4.3 percent on an average bank debt of $18.17 million in 2005, compared to 4.9 percent on an average bank debt of $8.88 million in 2004 and 4.5 percent on an average bank debt of $17.19 million in 2003. At year end 2005, Zargon's bank debt, net of working capital (excluding unrealized risk management liability), totalled $27.49 million, up 18 percent from $23.37 million at December 31, 2004.

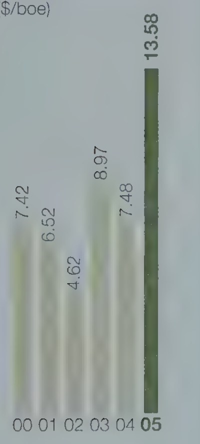
CAPITAL AND CURRENT INCOME TAXES

During 2005, Zargon incurred $1.80 million of current income taxes compared to $1.11 million in 2004. Of the total, $0.90 million is due to current taxes incurred in the United States compared to $0.61 million in 2004. Provided that oil prices remain high, a similar level of United States current income taxes is predicted in 2006. The remaining current tax amounts relate to federal and provincial capital taxes, which were $0.90 million in 2005 compared to $0.50 million in 2004. Tax pools as at December 31, 2005 were approximately $90 million which represents an increase from the comparable $79 million of tax pools available to Zargon at the end of 2004. The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on the income that is not

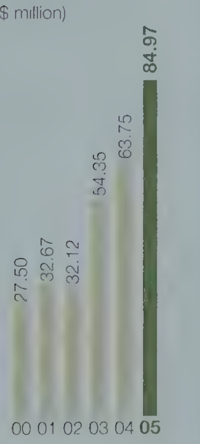
Cash Flow Netbacks
($/boe)



Earnings Before Non-Controlling Interest Netbacks
($/boe)



Cash Flow from Operations
($ million)



distributed or declared distributable to unitholders. It is anticipated that sufficient distributions will be made to eliminate current Canadian income tax. For Canadian income tax purposes, 2005 distributions are 100 percent taxable income to unitholders.

TRUST NETBACKS

Historically high oil prices and the continued strength of natural gas prices in 2005 resulted in higher revenue netbacks and operating netbacks. On a barrel of oil equivalent basis, revenue of $53.44 in 2005 was 30 percent higher than the prior year and operating netbacks as well as cash flow netbacks increased 33 percent and 32 percent over the prior year to $30.75 and $27.91 per barrel of oil equivalent, respectively.

TRUST NETBACKS

($/boe)	2005	2004	2003
Petroleum and natural gas revenue	**53.44**	41.20	37.40
Realized risk management loss	**(2.55)**	(1.52)	(1.06)
Royalties	**(12.25)**	(9.32)	(8.28)
Production costs	**(7.89)**	(7.21)	(6.33)
Operating netbacks	**30.75**	23.15	21.73
General and administrative	**(1.99)**	(1.45)	(1.30)
Interest and financing charges	**(0.26)**	(0.15)	(0.28)
Capital and current income taxes	**(0.59)**	(0.37)	(0.15)
Cash flow netbacks	**27.91**	21.18	20.00
Depletion and depreciation (1)	**(12.31)**	(9.11)	(7.23)
Unrealized risk management loss	**(1.24)**	–	–
Accretion of asset retirement obligations (1)	**(0.39)**	(0.36)	(0.43)
Unit-based compensation	**(0.30)**	(1.22)	(0.10)
Unrealized foreign exchange gain	**0.07**	0.19	0.11
Future income taxes (1)	**(0.16)**	(3.20)	(3.38)
Earnings before non-controlling interest (1)	**13.58**	7.48	8.97

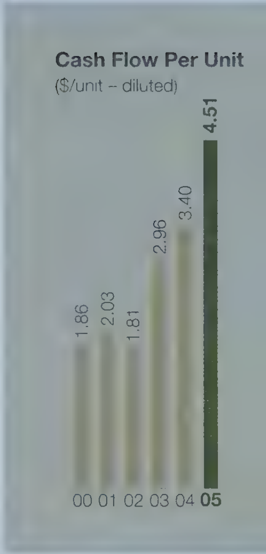
1. Comparative 2003 period numbers reflect the retroactive restatements due to a change in accounting policy.

CASH FLOW FROM OPERATIONS (see note at the beginning of the MD&A)

In 2005, production volumes held steady, but increases of 26 percent in oil and natural gas liquids prices and 32 percent in natural gas prices, produced a 33 percent gain in cash flow from operations to $84.97 million, compared to $63.75 million in 2004 and $54.35 million in 2003. The corresponding cash flow per diluted unit was $4.51 in 2005, a 33 percent gain from $3.40 per diluted unit in 2004, and compares to $2.96 in 2003. The diluted per unit statistics reflected a one percent increase in the weighted average outstanding units to 18.85 million in 2005, and a two percent increase in the average weighted number of outstanding units to 18.72 million in 2004 from 18.37 million in 2003.

The following table summarizes the variances in cash flow from operations between 2004 and 2005. It shows the variance is caused mainly by increased commodity pricing, with partial offset coming from increased royalties and higher realized risk management losses.

	$ Million	$ Per Diluted Trust Unit	Per Unit Percent Variance
Cash flow from operations – 2004	**63.75**	**3.40**	**–**
Price variance	36.95	1.97	58
Volume variance	1.81	0.10	3
Realized risk management losses	(3.19)	(0.17)	(5)
Royalties	(9.27)	(0.49)	(14)
Expenses:			
Production	(2.34)	(0.12)	(3)
General and administrative	(1.70)	(0.09)	(3)
Interest and financing charges	(0.35)	(0.02)	(1)
Current taxes	(0.69)	(0.04)	(1)
Weighted average trust units – diluted	–	(0.03)	(1)
Cash flow from operations – 2005	**84.97**	**4.51**	**33**



DEPLETION AND DEPRECIATION

In 2005, Zargon's depletion and depreciation provision increased 37 percent to $37.48 million, compared to $27.41 million in 2004 and $19.66 million in 2003. The higher charges reflect an increase of one percent in production volumes and a 35 percent increase in the charge on a per barrel of oil equivalent basis. This large increase in the per barrel of oil equivalent depletion and depreciation expense is primarily due to the increase in the property and equipment balance from the conversion of exchangeable shares due to the application of EIC-151. The effect of EIC-151 on depletion and depreciation expense results in an increase of $5.08 million or $1.67 per barrel of oil equivalent. Additionally, the write-off of 2.4 billion cubic feet of proved reserves related to the production loss at a significant well in the West Central Alberta core area also factors into the increase. The 2004 increase from 2003 resulted from a December 31, 2003 year-over-year 14 percent reduction in the Trust's proved reserves as calculated pursuant to the implementation of the National Instrument 51-101 standards of reserve disclosure policy.

Depletion and depreciation charges calculated on a unit of production method are based on total proved reserves with a conversion of six thousand cubic feet of natural gas being equivalent to one barrel of oil. The 2005 depletion calculation includes $6.88 million of future capital expenditures to develop the Trust's reserves, but excludes $14.72 million of unproven properties relating to undeveloped land.

Zargon's depletion and depreciation, on a barrel of oil equivalent basis, increased 35 percent in 2005 to $12.31 from $9.11 in 2004 and $7.23 in 2003. Depletion and depreciation rates will be subject to continuing upward pressure as industry finding and development costs increase to reflect the new economics of the recent trends to substantially higher commodity prices.

ACCRETION OF ASSET RETIREMENT OBLIGATIONS

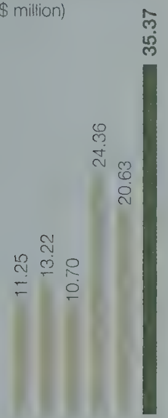
For the year ended December 31, 2005, the non-cash accretion expense for asset retirement obligations is $1.20 million compared to $1.08 million in 2004 and $1.17 million in 2003. The significant assumptions used in this calculation are a credit adjusted risk-free rate of 7.5 percent, an inflation rate of two percent and the payments to settle the retirement obligations will be made

over the next 30 years with the majority of the costs being incurred after 2012. The estimated net present value of the total asset retirement obligation is $15.86 million as at December 31, 2005, based on a total future liability of $62.54 million.

UNIT-BASED COMPENSATION

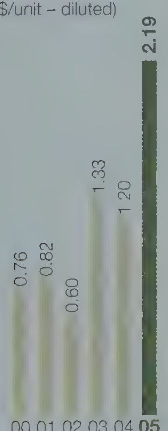
Unit-based compensation was $0.90 million in 2005 or $2.78 million lower than the $3.68 million expense in 2004. Of the 2004 amount, $2.17 million was related to a one-time charge for the accelerated vesting of stock options related to the July 15, 2004 Arrangement. The remainder was primarily the expense for the trust unit rights incentive plan, which in 2004 were originally calculated using the intrinsic value method. In response to an emphasis by securities regulators that fair value methodologies be used, new measurement techniques have been developed in 2005 utilizing a fair value option-pricing model for such unit rights grants. Zargon has reassessed the previous unit rights grants under this fair value model and there is no significant impact on amounts previously recorded as 2004 unit-based compensation expense. Zargon will continue to use fair value methodologies, where possible, for future unit rights grants. These non-cash expenses will be recurring charges in future years if Zargon continues to grant employee and director trust unit rights.

Net Earnings
($ million)



The trust unit rights incentive plan allows the Trust to issue rights to acquire trust units to directors, officers, employees and service providers. The Trust is authorized to issue up to 1.82 million unit rights; however, the number of trust units reserved for issuance upon exercise of the rights shall not exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust. The plan allows for the holder of rights to either exercise the right based on the original grant price or on the original grant price reduced by a portion of the future distributions. Unit right grant prices are set at the market price for the trust units on the date the unit rights are issued. Trust unit rights granted under the plan generally vest over a three-year period and expire approximately five years from the grant date.

Net Earnings Per Unit
($/unit – diluted)



FUTURE INCOME TAXES

Zargon's 2005 future tax expense decreased 95 percent to $0.47 million when compared to the respective expenses for 2004 and 2003 of $9.64 million and $9.19 million. The effective future tax rate in 2005 (the first full year in the trust structure) was 1.1 percent and is no longer comparable to the 2004 future tax rate of 29.0 percent and the 2003 rate of 27.1 percent. Effectively, Zargon's future tax obligations are reduced as distributions are made from the Trust, and consequently it is anticipated that Zargon's effective 2006 future tax rate will continue to be at considerably lower levels than the future tax rates booked prior to Zargon's conversion into a trust.

NET EARNINGS

Zargon's 2005 net earnings were $35.37 million, a $14.74 million increase from $20.63 million in 2004. The 2003 net earnings were $24.36 million. The very strong 2005 increase was due primarily to the $21.23 million increase in cash flow from operations as previously described. On a per diluted unit basis, 2005 net earnings were $2.19 compared to $1.20 in 2004 and $1.33 in 2003.

On a barrel of oil equivalent basis, the 2005 earnings before non-controlling interest were $13.58 compared to $7.48 in 2004 and $8.97 in 2003.

Reflecting primarily the reduction in future income taxes, the 2005 net earnings were 42 percent of cash flow from operations. The 2004 net earnings represented 32 percent of cash flow from operations compared to 45 percent of cash flow in 2003.

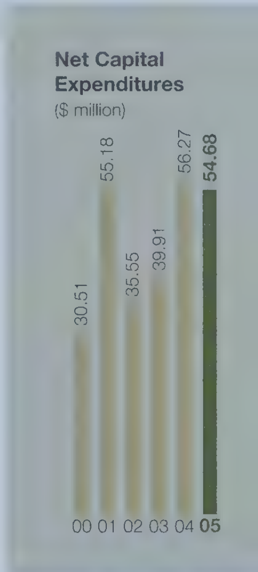
CAPITAL EXPENDITURES

Net capital expenditures in 2005 of $54.68 million decreased three percent from $56.27 million in 2004. The decrease in capital expenditures was a result of a decline in Zargon's 2005 net property acquisition program to $1.23 million from the prior year's $11.81 million purchase of producing Saskatchewan oil properties in the Williston Basin core area. In 2005, Zargon completed an expanded drilling program of 60 gross (53.5 net) wells and drilling and completion expenditures climbed commensurately by 24 percent to $33.36 million. Of the total 2005 net capital expenditures, $15.77 million was expended on West Central Alberta, $19.07 million on Alberta Plains and $19.84 million on Williston Basin properties.

CAPITAL EXPENDITURES

($ million)	**2005**	2004	2003
Undeveloped land	**3.65**	3.84	6.98
Geological and geophysical (seismic)	**3.47**	5.26	5.69
Drilling and completion of wells	**33.36**	26.94	17.30
Well equipment and facilities	**11.78**	8.42	7.33
Exploration and development	**52.26**	44.46	37.30
Property acquisitions	**3.68**	12.09	7.83
Property dispositions	**(2.45)**	(0.28)	(5.22)
Net property acquisitions	**1.23**	11.81	2.61
Corporate acquisitions assigned to property and equipment [1]	**1.19**	–	–
Total net capital expenditures [1]	**54.68**	56.27	39.91

1. Amounts include capital expenditures acquired for cash and equity issuances.



LIQUIDITY AND CAPITAL RESOURCES

Zargon's financing philosophy and three sources of funding are as follows:

- Internally generated cash flow provides the basic level of funding for the Trust's annual capital expenditures program and for distributions to unitholders.
- Debt may be utilized for acquisitions or to expand capital programs when it is deemed appropriate. The Trust has an $80 million syndicated committed credit facility. As at December 31, 2005, $69.66 million or 87 percent of this facility is unutilized. The Trust has followed and intends to maintain a conservative debt policy.
- New equity, if available and if on favourable terms, can be utilized for acquisitions or to expand capital programs.

In 2005, the summation of the cash outflows pertaining to the net capital expenditure program ($54.68 million) and the cash distributions to unitholders ($37.44 million) exceeded by $3.28

million the summation of the cash inflows coming from the cash flow from operations ($84.97 million) plus the proceeds from the issuance of trust units ($3.87 million).

CAPITAL SOURCES

($ million)	**2005**	2004	2003
Cash flow from operations	**84.97**	63.75	54.35
Changes in working capital and other	**7.17**	2.54	2.66
Change in bank debt	**(3.89)**	7.25	(18.30)
Reorganization costs	**–**	(9.44)	–
Cash distributions	**(37.44)**	(10.70)	–
Issuance of trust units	**3.87**	2.87	1.20
Total capital sources	**54.68**	56.27	39.91

CASH FLOW FROM OPERATIONS

It is anticipated that Zargon's 2006 capital budget and cash distributions to unitholders will be financed through the Trust's cash flow from operations. Cash flow is partially influenced by factors that the Trust cannot control, such as commodity prices, the US/Canadian dollar exchange rates and interest rates. Zargon's 2006 estimated sensitivity to moderate fluctuations in these key business parameters is shown in the accompanying table.

CASH FLOW SENSITIVITY SUMMARY

	Change in 2006 Cash Flow ($ million)	($/unit)
Change of $1.00 US/bbl in the price of WTI oil	0.86	0.04
Change in oil production of 100 bbl/d	0.82	0.04
Change of $0.10 US/mcf in the price of NYMEX natural gas	0.74	0.04
Change in natural gas production of one mmcf/d	1.76	0.09
Change in $0.01 in the $US/$Cdn exchange rate	1.39	0.07

BANK DEBT

On September 30, 2005, a Canadian subsidiary and a US subsidiary of the Trust entered into syndicated committed credit facilities with a borrowing base of $80 million, which replaces its former demand facility of $50 million. These facilities consist of a $60 million tranche available to the Canadian borrower and a US $15 million tranche available to the US borrower. A $150 million demand debenture on the assets of the subsidiaries of the Trust has been provided as security for these facilities. These facilities are fully revolving for a 364 day period with the provision for an annual extension at the option of the lenders and upon notice from the Company. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 364 day period. Repayment would not be required until the end of the non-revolving term, and as such, in accordance with Canadian GAAP, the revolving credit facility has been classified as long term debt as opposed to the previous facility which was treated as a current liability. At December 31, 2005, bank debt was $10.34 million, a decrease of 27 percent from the prior year end bank indebtedness amount of $14.23 million.

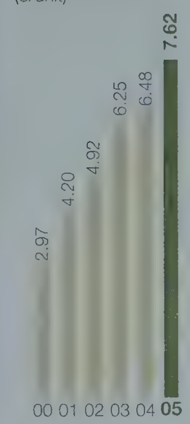
Zargon's debt net of working capital (excluding the unrealized risk management liability) of $27.49 million at December 31, 2005 was equivalent to 32 percent of the 2005 cash flow from operations of $84.97 million. At December 31, 2004, the debt net of working capital (excluding the unrealized risk management liability) was $23.37 million, equivalent to 37 percent of the 2004 cash flow from operations of $63.75 million.

EQUITY

At March 13, 2006, Zargon had 16.461 million trust units and 2.345 million exchangeable shares outstanding. Assuming full conversion of exchangeable shares at the effective exchange ratio of 1.12640, there would be 19.101 million trust units outstanding at this date. Pursuant to the trust unit rights incentive plan, there are currently an additional 0.986 million trust unit incentive rights issued and outstanding.

During 2005, 13.18 million Zargon trust units traded on The Toronto Stock Exchange with a high trading price of $34.99 per unit, a low of $20.75 per unit and a closing price of $31.75 per unit. The 2005 trading statistics show a 26 percent year-over-year decrease in trading volume, and a 33 percent increase in the closing stock price. Zargon's market capitalization (including the market value of exchangeable shares) at year end 2005 was approximately $603 million, compared to approximately $444 million at the end of 2004.

Unitholders' Equity
($/unit)



SEGMENTED GEOGRAPHIC INFORMATION

In calendar 2005, approximately 87 percent (2004 – 88 percent) of Zargon's combined petroleum and natural gas revenue came from Western Canadian (Alberta, Saskatchewan and Manitoba) properties, with the remaining 13 percent (2004 – 12 percent) of revenues generated in the United States (North Dakota and Montana).

Zargon Year End Trust Unit Price
($ million)

OFF BALANCE SHEET ARRANGEMENTS

The Trust has no guarantees or off balance sheet arrangements, except for letters of credit which have been issued in the normal course of business of approximately $0.47 million as at December 31, 2005.

RELATED PARTY TRANSACTIONS

During the year, the Trust paid $0.13 million for consulting fees to a company owned by the Chairman of the Board, $0.04 million for vehicle leasing costs to a company associated with a member of the Board of Directors and $0.12 million for legal fees to a law firm associated with a member of the Board of Directors. All amounts were based on normal commercial terms and conditions.

CONTRACTUAL OBLIGATIONS

Zargon has certain contractual obligations relating to the lease of head office space, field operating leases and transportation contracts that extend for longer than one year as set out in the table below:

($ million)	Total	2006	2007 to 2008	2009 to 2010	Thereafter
Head office lease and other	1.16	0.71	0.44	0.01	–
Field operating leases	0.17	0.17	–	–	–
Transportation contracts	0.77	0.56	0.20	0.01	–
Total	2.10	1.44	0.64	0.02	–

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. Zargon's management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. The critical estimates are discussed below:

PETROLEUM AND NATURAL GAS RESERVES

All of Zargon's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Trust expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels, and changes in costs and commodity prices.

FULL COST ACCOUNTING

Zargon follows the full cost method of accounting for petroleum and natural gas operations as outlined in Canadian Institute of Chartered Accountants ("CICA") accounting guideline "Oil and Gas Accounting – Full Cost" (AcG-16). Under this accounting method, all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proved reserves, are depleted using the unit-of-production method based on estimated proved oil and natural gas reserves.

In applying the full cost method, Zargon calculates a ceiling test on a quarterly basis to ensure that the net carrying value of petroleum and natural gas assets do not exceed the estimated undiscounted future net cash flows from production of proved reserves. Accordingly, the Trust must base this calculation of future net cash flows on estimated forecasted sales prices, costs and regulations in effect at the period end. AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flows from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, Zargon adopted CICA Section 3110, "Asset Retirement Obligations", which requires liability recognition for retirement obligations associated with the Trust's property, plant and equipment. Under this policy, the Trust is required to provide for future removal and site restoration costs. The Trust must estimate these costs in accordance with existing laws, contracts or other policies and must also estimate a credit adjusted risk-free rate and inflation rate in this calculation. These estimated costs are charged to earnings and the appropriate liability account over the expected life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

INCOME TAX ACCOUNTING

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

RECENT CANADIAN ACCOUNTING PRONOUNCEMENTS

During 2005, the following new or amended standards and guidelines were issued:

EXCHANGEABLE SECURITIES ISSUED BY SUBSIDIARIES OF INCOME TRUSTS

On January 19, 2005, the CICA issued revised draft EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" which states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as non-controlling interest. Previously, the exchangeable shares were reflected as a component of unitholders' equity.

For the 2004 year end, the Trust retroactively restated prior periods back to the Plan of Arrangement dated July 15, 2004. As a result of this change in accounting policy, the Trust has increased its unitholders' equity and non-controlling interest for 2005 by $24.44 million (2004 – $10.15 million) on the Trust's consolidated balance sheet. Consolidated net earnings for 2005 have been reduced for net earnings attributable to the non-controlling interest of $5.99 million (2004 – $1.87 million). In accordance with EIC-151 and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which for 2005 additionally resulted in an increase in property and equipment of $24.93 million (2004 – $11.28 million), an increase in accumulated depletion and depreciation by $5.08 million (2004 – nil), and an increase in future income tax liability of $6.48 million (2004 – $3.00 million). Cash flow was not impacted by this change.

The cumulative impact to date of the application of EIC-151 has been to increase gross property and equipment by $36.21 million, unitholders' equity and non-controlling interest by $34.59 million, future income tax liability by $9.48 million and an allocation of net earnings to exchangeable shareholders' of $7.86 million.

FINANCIAL INSTRUMENTS – RECOGNITION AND MEASUREMENT

On January 27, 2005, the Accounting Standard's Board (AcSB) issued CICA Handbook section 3855 "Financial Instruments – Recognition and Measurement", CICA Handbook section 3861 "Financial Instruments – Disclosure and Presentation", CICA Handbook section 1530 "Comprehensive Income" and CICA handbook section 3865 "Hedges" that deal with the recognition and measurement of financial instruments and comprehensive income. The new standards are intended to harmonize Canadian standards with United States and International accounting standards and are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. These new standards will impact the Trust in future periods and the resulting impact will be assessed at that time.

NON-MONETARY TRANSACTIONS

In the quarter ending March 31, 2006, Zargon will adopt Section 3831 "Non-Monetary Transactions" issued by the CICA in June 2005. Under the new standard, a commercial substance test replaces the culmination of earnings test as the criteria for fair value measurement. In addition, fair value measurement is clarified. The Trust does not expect application of this new standard to have a material impact on its consolidated financial statements.

TRUST STRUCTURE DEVELOPMENT

NO CHANGE TO TAX TREATMENT OF INCOME TRUSTS

On November 23, 2005, the federal government of Canada announced a reduction in personal income taxes on dividends and an end to the consultation process initiated on September 8, 2005 to review the tax treatment of income trusts and flow-through entities. The government did not announce any changes to the tax treatment of income trusts and flow-through entities.

The Trust's management believes that the announcement reflects the overwhelming consensus of submissions received during the consultation process to reduce personal income tax on corporate dividends to correct the long-standing problem of double taxation of dividends at the federal level. The decision reduces the uncertainty surrounding income trust taxation and assists in balancing tax treatment between corporations and trusts.

MANAGEMENT AND FINANCIAL REPORTING SYSTEMS

EVALUATION OF DISCLOSURE CONTROL AND PROCEDURES

The Trust has established procedures and internal control systems to ensure timely and accurate preparation of financial, internal management and other reports. Disclosure controls and procedures are in place to ensure all ongoing statutory reporting requirements are met and material information is disclosed on a timely basis. The President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer, individually, sign certifications that the financial statements together with the other financial information included in the regulatory filings fairly present in all material respects the financial conditions, results of operation, and cash flows as of the dates and for the periods represented.

Our management, including our President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer, have evaluated the effectiveness of the Trust's disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer, have concluded that the Trust's disclosure controls are effective as of the end of the period covered by this annual report, in all material respects, after considering the Canadian Securities Administrator's Multilateral Instrument 52-109 "Certification of Disclosures in Issuers' Annual and Interim Filings."

BUSINESS RISKS AND OUTLOOK

BUSINESS RISKS

Zargon's external business risks arise from the uncertainty of oil and natural gas pricing, the uncertainty of interest and exchange rates, environmental and safety issues, and financial and liquidity considerations. Additional risk arises from the production performance of existing properties (including natural decline), the changes in tax, royalty and other regulatory standards and uncertain results from capital expenditure programs.

Oil and natural gas prices may fluctuate widely in response to many factors such as global and North American supply and demand, economic conditions, weather conditions, political stability, the supply and price of imported oil and liquefied natural gas, production and storage levels of North American natural gas, and government regulations. Zargon attempts to minimize pricing and currency exchange uncertainty with a risk management program that encompasses a variety of financial instruments. These include forward sales of oil and natural gas production (either through financial derivative transactions such as swaps or by physical contracts), put options on both oil and natural gas, costless collars (in which some potential high price gain is given up in return for potential low price support) and US dollar currency risk management transactions in different forms for up to 35 percent of its oil and natural gas production volumes. In general, the Trust seeks to use strategies that allow minimum price expectations to be met in order that distributions and capital programs can be funded. This strategy is designed mainly to protect the Trust against periods of unusually low commodity prices and by its nature is likely to produce significant risk management losses when prices are unusually high.

Environmental and safety risks are mitigated through compliance with provincial and federal environmental and safety regulations, by maintaining adequate insurance, and by adopting appropriate emergency response and employee safety procedures.

The Trust is subject to a broad range of laws and regulatory requirements. Changes in government regulations, including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates can have a significant impact on Zargon. Although Zargon has no control over these regulatory risks, the Trust actively monitors changes, participates in industry organizations and, when required, engages the assistance of third-party experts to assess the impact of such changes in the Trust's financial and operating results.

Financial and liquidity risks are reduced by limiting debt financing to conservative self-imposed debt to cash flow guidelines. Zargon maintains a low cash distribution to cash flow from operations ratio to ensure adequate funding is available for capital programs to sustain per unit production and reserves. Access to capital markets, if required for additional financing by either debt or equity issuances, is dependent upon maintaining strong performance and relationships with investors. A substantial portion of the Trust's accounts receivable are with companies in the oil and gas industry and are subject to normal industry credit risks. Management regularly monitors the ageing of receivable balances to mitigate this risk. With respect to financial instruments utilized for risk management purposes, the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Zargon actively manages the risks of its capital programs and reserves by concentrating drilling and subsequent development activities in areas where it has demonstrated proven technical capabilities and understanding. Zargon's capital budget is managed to limit exposure so that significant capital is not risked on any one project or concept.

OUTLOOK

As a sustainable trust, Zargon is committed to maintaining reserves, production and distributions per unit in the context of distributing approximately 50 percent of its cash flow from operations to unitholders. For calendar 2006, Zargon has budgeted $45 million of capital expenditures allocated to natural gas exploration and oil exploitation and is projecting an average production rate of approximately 8,600 barrels of oil equivalent per day. This amount does not include any allocation for opportunistic corporate or property acquisitions which, if available, would be funded by bank debt or equity issues.

SELECTED QUARTERLY INFORMATION [1]

	2005				2004			
($ million, except per unit amounts)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Petroleum and natural gas revenue	**50.26**	**42.47**	**35.87**	**34.12**	32.90	32.41	30.96	27.70
Cash flow from operations	**26.62**	**21.85**	**19.01**	**17.48**	15.36	16.13	16.53	15.73
Per unit – diluted	**1.40**	**1.15**	**1.01**	**0.93**	0.82	0.87	0.88	0.84
Net earnings [1]	**17.45**	**6.30**	**6.48**	**5.14**	5.33	4.22	5.54	5.54
Per unit – diluted [1]	**1.06**	**0.39**	**0.41**	**0.32**	0.34	0.28	0.29	0.30
Cash distributions	**16.66**	**7.45**	**6.73**	**6.60**	6.43	4.27	–	–
Cash distribution – per trust unit	**1.02**	**0.46**	**0.42**	**0.42**	0.42	0.28	–	–
Net capital expenditures [2]	**19.12**	**13.91**	**10.96**	**10.69**	15.25	23.64	7.61	9.77
Total assets [1]	**277.86**	**264.44**	**253.75**	**245.20**	226.96	215.23	189.80	186.18
Bank debt	**10.34**	**11.43**	**15.52**	**18.23**	14.23	9.77	–	3.67

1. Comparative period numbers reflect the retroactive restatements due to changes in accounting policies.

2. Amounts include capital expenditures acquired for cash and equity issuances.

FOURTH QUARTER 2005 HIGHLIGHTS

During the fourth quarter of 2005, Zargon's petroleum and natural gas revenues of $50.26 million were 18 percent higher than the previous quarter's revenues. Production for the 2005 fourth quarter of 8,651 barrels of oil equivalent per day exceeded the fourth quarter guidance of 8,500 barrels of oil equivalent per day by two percent and was eight percent higher than the 2005 third quarter's production of 8,036 barrels of oil equivalent per day. Compared to the previous quarter, oil production increased 13 percent to 4,030 barrels per day as two successful higher rate Williston Basin horizontal wells were drilled and placed on production. Fourth quarter natural gas production increased four percent over the previous quarter to 27.73 million cubic feet per day as recently drilled West Central Alberta and Alberta Plains natural gas wells were tied-in to help offset the previous quarter's production losses at a significant well in the West Central Alberta core area. Average prices received during the fourth quarter, before risk management losses, were $57.58 per barrel for oil and liquids and $11.34 per thousand cubic feet for natural gas, a 13 percent reduction and a 34 percent increase respectively, compared to the 2005 third quarter prices. Reflecting market and seasonal trends, Zargon's field price differential for its blended 30 degree API crude oil stream increased to a $13.59 per barrel discount to the Edmonton reference crude oil price, a 24 percent increase from Zargon's average differential of $10.92 per barrel for the first nine months of 2005.

Cash flow from operations was $26.62 million in the fourth quarter, an increase of 22 percent or $4.77 million over the prior quarter. A comparative analysis of the primary factors that caused this quarter-over-quarter increase are as follows:

- Realized risk management losses increased by $0.50 million to $3.12 million, a 19 percent increase over the prior quarter's $2.62 million of risk management losses. The primary reason for the increase in the fourth quarter related to losses on natural gas risk management contracts due to the high natural gas prices received throughout the quarter.
- Royalties for the fourth quarter were $11.59 million, an increase of $1.81 million from the prior quarter. The average royalty rate for the quarter held relatively steady at 23.1 percent from 23.0 percent from the third quarter.
- Production expenses held steady at $6.10 million for the quarter, a $0.19 million or three percent decrease from the third quarter of 2005. On a per barrel of oil equivalent basis, production expenses decreased 10 percent to $7.67 in the fourth quarter 2005 compared to $8.52 in the prior quarter. The quarterly improvement in per unit costs reflected the impact of the addition of higher-rate lower-cost wells that were responsible for the Trust's eight percent quarter-over-quarter production gain.
- General and administrative expenses increased in the fourth quarter by $0.49 million over the third quarter of 2005. This is a 32 percent increase compared to the prior quarter and is primarily due to amounts recorded for year end performance-based compensation for employees.
- Interest and financing charges in the fourth quarter were $0.23 million, an increase of 35 percent or $0.06 million from the prior quarter. This increase is primarily due to additional costs related to the Trust's new syndicated committed credit facility which was closed and available on September 30, 2005. The average debt level for the fourth quarter declined slightly to $16.40 million compared to $17.63 million in the third quarter of 2005.
- Capital and current income taxes increased by $0.36 million from the third quarter of 2005. The increase was due to increases in Canadian capital taxes and an increase in United States current income taxes incurred as a result of strengthening United States operations.

Net earnings for the quarter increased $11.16 million to $17.45 million, a 177 percent increase compared to the third quarter 2005 net earnings of $6.30 million. Net earnings track the cash flow from operations for the respective periods modified by non-cash charges, which included the following for the fourth quarter of 2005:

- Unit-based compensation expense increased by $0.06 million during the fourth quarter of 2005 to $0.24 million, a 32 percent increase over the third quarter. The increase is a result of additional unit rights grants in the fourth quarter of 2005.
- Depletion and depreciation expense increased by $1.04 million to $10.36 million in the fourth quarter. The additional expense resulted from the use of an updated depletion and depreciation rate of $13.02 per barrel of oil equivalent, compared to the prior quarter's $12.61 per barrel of oil equivalent charge. The increased per unit charges are calculated on the basis of the recently completed 2005 year end reserve appraisal prepared by independent engineers that reflects Zargon's and the ongoing industry's trend to higher finding and development costs, which are commensurate with the new economics of this current era of substantially higher commodity prices. Furthermore, 2005 depletion and depreciation rates continue to increase quarterly as a

result of ongoing increases in the property and equipment balance from the conversion of exchangeable shares due to the application of EIC-151. Additionally, the 2005 third quarter write-off of proved reserves of 2.4 billion cubic feet related to the production loss at a significant well in the West Central Alberta core area also factors into the fourth quarter increase.

- Unrealized risk management losses in the third quarter of $5.30 million reverted to gains in the 2005 fourth quarter of $4.89 million. These unrealized gains and losses result from "marking-to-market" risk management contracts at each period end. During the fourth quarter, unrealized risk management gains were primarily driven by weaker commodity pricing at the December 31, 2005 marking-to-market date when compared to the third quarter September 30, 2005 marking-to-market date. In particular, lower year end futures natural gas pricing resulted in gains of $3.27 million, and moderately lower year end futures oil pricing resulted in gains of $1.62 million.
- Future income tax expense was $0.33 million during the quarter, compared to a future income tax recovery of $0.23 million from the third quarter of 2005. As cash distributions are made from the Trust, future tax expenses decline. During the fourth quarter, in addition to regular monthly distributions, a supplemental cash distribution was declared to unitholders. Future income taxes increased in the 2005 fourth quarter despite increased cash distributions due to the significant increase of earnings before taxes to $21.20 million from the third quarter earnings before taxes of $7.36 million.
- Non-controlling interest related to exchangeable shares increased to $2.81 million in the 2005 fourth quarter, from $1.05 million in the third quarter. This was due to an increase in net earnings before non-controlling interest in the fourth quarter.

Net capital expenditures were $19.12 million during the fourth quarter of 2005, a 37 percent increase from the prior quarter amount of $13.91 million. During the fourth quarter, Zargon completed a record field capital program focused on more expensive activities in the West Central Alberta and Williston Basin core areas. The fourth quarter capital expenditures were complemented with the corporate acquisition of a small private Saskatchewan oil and gas company for consideration of $1.19 million. During the fourth quarter of 2005, 15.3 net wells were drilled, compared to 16.2 net wells in the third quarter of 2005.

On November 14, 2005, Zargon announced its monthly distribution rate would be increased an additional $0.02 per unit to $0.18 per unit commencing with the November distribution. A supplemental distribution (over-and-above the monthly distribution) was declared in December 2005 of $0.50 per unit, raising the distribution per unit to $1.02 for the fourth quarter from $0.46 in the prior quarter. Cash distributions to unitholders declared for the quarter totalled $16.66 million, resulting in a quarterly payout ratio of 63 percent of cash flow or 73 percent on a per diluted trust unit basis. The upward spike in the fourth quarter was a result of the December 2005 supplemental distribution which represented a semi-annual adjustment pursuant to Zargon's strategy of distributing approximately 50 percent of the Trust's cash flows attributed to the unitholder.

ADDITIONAL INFORMATION

Additional information regarding the Trust and its business operations, including the Trust's Annual Information Form for December 31, 2005, is available on the Trust's SEDAR profile at www.sedar.com.

MANAGEMENT'S AND AUDITORS' REPORTS

MANAGEMENT'S REPORT

The consolidated financial statements of Zargon Energy Trust were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the financial statements reliably report the Trust's operations and that the Trust's assets are safeguarded. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

Ernst & Young LLP, an independent chartered accountant firm, was appointed by a resolution of the unitholders to audit the financial statements of the Trust and provide an independent opinion. They have conducted an independent examination of the Trust's accounting records in order to express their opinion on the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management directors, has met with Ernst & Young LLP and management in order to determine that management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Audit Committee has reported its findings to the Board of Directors, who have approved the consolidated financial statements.

C.H. Hansen
President and Chief Executive Officer

B.C. Heagy
Vice President, Finance and Chief Financial Officer

Calgary, Canada
March 13, 2006

AUDITORS' REPORT

To the Unitholders of Zargon Energy Trust

We have audited the consolidated balance sheets of Zargon Energy Trust as at December 31, 2005 and 2004 and the consolidated statements of earnings and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

Calgary, Canada
March 13, 2006

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ thousand)	**2005**	2004
ASSETS [note 6]		
Current		
Accounts receivable [note 12]	**21,835**	14,275
Prepaid expenses and deposits	**2,710**	2,953
	24,545	17,228
Property and equipment, net [notes 4 and 5]	**253,315**	209,736
	277,860	226,964
LIABILITIES		
Current		
Bank indebtedness [note 6]	**–**	14,230
Accounts payable and accrued liabilities	**30,570**	24,153
Cash distributions payable [note 18]	**11,122**	2,210
Unrealized risk management liability [note 12]	**3,756**	–
	45,448	40,593
Long term debt [note 6]	**10,339**	–
Asset retirement obligations [note 7]	**15,859**	14,390
Future income taxes [note 10]	**48,928**	41,830
	120,574	96,813
Commitments and contingencies [notes 12, 13 and 14]		
NON-CONTROLLING INTEREST		
Exchangeable shares [notes 3 and 9]	**12,673**	9,529
UNITHOLDERS' EQUITY		
Unitholders' capital [note 8]	**71,644**	45,755
Contributed surplus [note 8]	**1,347**	1,170
Accumulated earnings	**119,768**	84,399
Accumulated cash distributions [note 18]	**(48,146)**	(10,702)
	144,613	120,622
	277,860	226,964

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

J.O. McCutcheon
Director

K.D. Kitagawa
Director

CONSOLIDATED STATEMENTS OF EARNINGS AND ACCUMULATED EARNINGS

For the years ended December 31 ($ thousand, except per unit amounts)	2005	2004
REVENUE		
Petroleum and natural gas revenue	**162,722**	123,968
Unrealized risk management loss [note 12]	**(3,756)**	–
Realized risk management loss [note 12]	**(7,754)**	(4,568)
Royalties (net of Alberta Royalty Credit)	**(37,319)**	(28,047)
	113,893	91,353
EXPENSES		
Production	**24,035**	21,692
General and administrative [note 20]	**6,053**	4,358
Unit-based compensation [note 8]	**902**	3,682
Interest and financing charges [note 6]	**786**	440
Unrealized foreign exchange gain	**(201)**	(564)
Accretion of asset retirement obligations [note 7]	**1,196**	1,076
Depletion and depreciation	**37,484**	27,414
	70,255	58,098
EARNINGS BEFORE INCOME TAXES	**43,638**	33,255
INCOME TAXES [note 10]		
Future	**474**	9,639
Current	**1,801**	1,114
	2,275	10,753
EARNINGS FOR THE YEAR BEFORE NON-CONTROLLING INTEREST	**41,363**	22,502
Non-controlling interest – exchangeable shares [notes 3 and 9]	**(5,994)**	(1,870)
NET EARNINGS FOR THE YEAR	**35,369**	20,632
ACCUMULATED EARNINGS, BEGINNING OF YEAR	**84,399**	70,005
Reorganization costs upon trust conversion [note 19]	**–**	(6,238)
ACCUMULATED EARNINGS, END OF YEAR	**119,768**	84,399
NET EARNINGS PER UNIT [note 11]		
Basic	**2.21**	1.23
Diluted	**2.19**	1.20

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ thousand)	**2005**	2004
OPERATING ACTIVITIES		
Net earnings for the year	**35,369**	20,632
Add (deduct) non-cash items:		
Non-controlling interest – exchangeable shares	**5,994**	1,870
Unrealized risk management loss	**3,756**	–
Depletion and depreciation	**37,484**	27,414
Accretion of asset retirement obligations	**1,196**	1,076
Unit-based compensation	**902**	3,682
Unrealized foreign exchange gain	**(201)**	(564)
Future income taxes	**474**	9,639
	84,974	63,749
Asset retirement expenditures	**(604)**	(414)
Changes in non-cash working capital [note 15]	**(1,401)**	19
	82,969	63,354
FINANCING ACTIVITIES		
Advances (repayment) of bank debt	**(3,891)**	7,252
Cash distributions to unitholders	**(37,444)**	(10,702)
Exercise of unit rights	**2,723**	2,867
Changes in non-cash working capital [note 15]	**8,974**	2,148
	(29,638)	1,565
INVESTING ACTIVITIES		
Additions to property and equipment	**(55,986)**	(56,553)
Proceeds on disposal of property and equipment	**2,446**	280
Reorganization costs [note 19]	**–**	(9,443)
Changes in non-cash working capital [note 15]	**209**	797
	(53,331)	(64,919)
CHANGE IN CASH, AND CASH END OF YEAR	**–**	–

See supplementary information contained in note 16.

See accompanying notes to the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2005 and 2004.
All amounts are stated in Canadian dollars unless otherwise noted.

1. STRUCTURE OF THE TRUST

On July 15, 2004, Zargon Oil & Gas Ltd. (the "Company") was reorganized into Zargon Energy Trust (the "Trust" or "Zargon") as part of a Plan of Arrangement (the "Arrangement"). Shareholders of the Company received one trust unit or one exchangeable share for each common share held. All outstanding common share options were settled for cash prior to the completion of the reorganization. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust. Holders of exchangeable shares are not eligible to receive cash distributions paid, but rather, on each payment of a distribution, the number of trust units into which each exchangeable share is exchangeable is increased on a cumulative basis in respect of the distribution. The Trust is an unincorporated open-end investment trust established under the laws of the Province of Alberta and was created pursuant to a trust indenture ("Trust Indenture").

The Trust's principal business activity is the exploration for and development and production of petroleum and natural gas in Canada and the United States ("US").

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

CONSOLIDATION AND BASIS OF PRESENTATION

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies summarized below.

While the Trust commenced operations on July 15, 2004, these consolidated financial statements follow the continuity of interest basis of accounting as if the Trust had always existed. This basis is intended to provide unitholders with meaningful and comparative financial information.

The consolidated financial statements include the accounts of Zargon Energy Trust, all subsidiaries and a partnership. All subsidiaries and the partnership are directly or indirectly owned and their operations are fully reflected in the consolidated financial statements.

REVENUE RECOGNITION

Petroleum and natural gas revenue is recognized in earnings when reserves are produced and delivered to the purchaser.

JOINT OPERATIONS

The majority of the petroleum and natural gas operations of the Trust are conducted jointly with others, and accordingly, these financial statements reflect only the proportionate interests of the Trust in such activities.

PROPERTY AND EQUIPMENT

The Trust follows the full cost method of accounting for its oil and natural gas operations whereby all costs relating to the acquisition, exploration and development of oil and natural gas reserves are

capitalized and accumulated in separate cost centres for Canada and the United States. Such costs include land acquisition costs, annual carrying charges of non-producing properties, geological and geophysical costs, and costs of drilling and equipping wells.

Depletion and depreciation of petroleum, natural gas properties and equipment is computed using the unit of production method based on the estimated proved reserves of petroleum and natural gas before royalties determined by independent consultants. For purposes of this calculation, reserves are converted to common units on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil. A portion of the cost of petroleum and natural gas rights relating to undeveloped properties is excluded from the depletion calculation. Twenty percent of the year end balance of these costs is added to the depletion base each year. Proceeds on the disposal of petroleum and natural gas properties are applied against capitalized costs, with gains or losses not ordinarily recognized, unless such a disposal would result in a change in the depletion rate of 20 percent or more.

Depreciation of office equipment is provided using the declining balance method at an annual rate of 20 percent.

IMPAIRMENT TEST

The Trust applies an impairment test to petroleum, natural gas properties and equipment costs on a quarterly basis or more frequently as events or circumstances dictate. This impairment test is performed on both the Canadian and US cost centres. An impairment loss exists when the carrying amount of the Trust's petroleum, natural gas properties and equipment exceeds the estimated undiscounted future net cash flows associated with the Trust's proved reserves (before royalties). If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the fair value of the Trust's proved and probable reserves are charged to income. Reserves are determined pursuant to evaluation by independent engineers as dictated by National Instrument 51-101.

ASSET RETIREMENT OBLIGATIONS

Zargon recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed in the period. Actual costs incurred upon the settlement of the ARO are charged against the liability. Differences between the actual costs incurred and the fair value of the liability recorded are recognized to earnings in the period incurred.

FINANCIAL INSTRUMENTS

Derivative financial instruments are utilized to reduce commodity price risk associated with the Trust's production of oil and natural gas. The base prices for the commodities are sometimes denominated in US dollars and the Trust may also use such financial instruments to reduce the related foreign currency risk. Financial instruments may also be used from time to time to reduce interest rate risk on outstanding debt. The Trust does not enter into financial instruments for trading or speculative purposes.

The Trust follows a policy of using risk management instruments such as fixed price swaps, forward sales, puts and costless collars. The objective is to partially offset or mitigate the wide price swings commonly encountered in oil and natural gas commodities and in so doing protect a minimum level of cash flow in periods of low commodity prices.

For financial risk management contracts entered into prior to December 31, 2004, the Trust's policy was to designate each derivative financial instrument employed as a hedge of a specific portion of projected production over the term of the instrument. The Trust formally documented its risk management objectives and strategies for undertaking the hedged transactions, the hedging item, the nature of the specific risk exposures being hedged, the intended term of the hedge relationship, the method for assessing effectiveness and the method of accounting for the hedging relationship. The effectiveness of the derivative is assessed on an ongoing basis to ensure that the derivatives entered into are highly effective in offsetting changes in fair values of the hedged items. The instruments employed may be denominated in US or Canadian dollars. Gains or losses from all hedging contracts, other than forward sales settled by physical delivery, are recognized as hedging gains or losses when the sale of hedged production occurs. The Trust believes these derivative financial instruments used are effective as hedges over their term. In the event that a designated hedged item ceases to exist, any realized or unrealized gain or loss on such derivative commodity instruments is recognized in income immediately. If the hedge relationship is terminated, either via ineffectiveness or via termination of the designation, gains or losses previously deferred continue to be deferred and recognized when they are realized.

For financial risk management contracts entered into after December 31, 2004, the Trust does consider these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and, accordingly, for outstanding contracts not designated as hedges, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at the period end. These instruments have been recorded as an unrealized risk management liability in the consolidated balance sheet.

In the case of forward sales, the instrument can sometimes be satisfied by physical delivery. In the case of physical delivery, the payment is part of the normal revenue stream.

Foreign currency swap agreements may be used from time to time to manage the risk inherent in producing commodities whose price is based directly or indirectly on US dollars, using a notional principal equal to the projected monthly revenue from their sale. Payments or charges are calculated and paid according to the terms of the agreement, usually with monthly settlement. At December 31, 2005 and 2004 the Trust had no such financial instruments.

INCOME TAXES

The Trust follows the liability method of tax allocation in accounting for income taxes. Under this method, the Trust records future income taxes for the effect of any differences between the accounting and income tax basis of an asset or liability using income tax rates expected to apply in the years in which these temporary differences are expected to be recovered or settled. The effect on future

income tax assets and liabilities of a change in tax rates is recognized in net earnings in the period in which the change is substantively enacted.

FOREIGN CURRENCY TRANSLATION

The Trust uses the temporal method of foreign currency translation whereby the monetary assets and liabilities recorded in a foreign currency are translated into Canadian dollars at year end exchange rates, and non-monetary assets and liabilities at the exchange rates prevailing when the assets were acquired or liability incurred. Revenues and expenses are translated at the average rate of exchange for the year. Gains and losses on translation are included in the consolidated statements of earnings.

TRUST UNIT RIGHTS AND UNIT-BASED COMPENSATION

Under the Trust's unit rights incentive plan (the "Plan"), rights to purchase trust units are granted to directors, officers and employees at current market prices. The Plan allows for the exercise price of rights to be reduced in future periods by an amount that distributions exceed a stated return on assets. The unit-based compensation expense arising from unit rights granted upon the July 15, 2004 Plan of Arrangement and up to December 31, 2004 were originally calculated using the intrinsic value method. In response to an emphasis by securities regulators that fair value methodologies be used, new measurement techniques in 2005 have been developed utilizing a fair value option-pricing model for such unit rights grants. Zargon has reassessed the previous unit rights grants under this fair value model and there is no significant impact on amounts previously recorded as 2004 unit-based compensation expense. Zargon will continue to use fair value methodologies, where possible, for future unit rights grants. Under the fair value method of accounting for unit-based compensation the cost of the option is charged to earnings with an offsetting amount recorded to contributed surplus, based on an estimate of the fair value using a Black-Scholes option-pricing model. No compensation expense has been recorded on options issued prior to 2003 (see note 8). Forfeiture of rights are recorded as a reduction in expense in the period in which they occur.

PER UNIT AMOUNTS

Per unit amounts are calculated using the weighted average number of trust units outstanding during the period. Diluted per unit amounts are calculated using the treasury stock method to determine the dilutive effect of unit-based compensation. The Trust follows the treasury stock method, which assumes that the proceeds received from "in-the-money" trust unit rights and unrecognized future unit-based compensation expense are used to repurchase units at the average market rate during the period. Diluted per unit amounts also include exchangeable shares using the "if-converted" method, whereby it is assumed the conversion of the exchangeable securities occurs at the beginning of the reporting period (or at the time of issuance if later).

MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of property and equipment and the assessment of these assets for impairment are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

Inherent in the fair value calculation of asset retirement obligations, are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal and regulatory environments. To the extent

future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment is made to the property and equipment balance.

CASH DISTRIBUTIONS

The Trust declares monthly distributions of cash to unitholders of record on the last day of each calendar month. Pursuant to the Trust's policy, it will pay distributions to its unitholders subject to satisfying its financing covenants. Such distributions are recorded as distributions of equity upon declaration of the distribution.

3. CHANGES IN ACCOUNTING POLICIES

EXCHANGEABLE SHARES – NON-CONTROLLING INTEREST

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either a non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as a non-controlling interest. Previously, the exchangeable shares were reflected as a component of unitholders' equity.

For the 2004 year end, the Trust retroactively restated prior periods back to the Plan of Arrangement dated July 15, 2004. As a result of this change in accounting policy, the Trust has increased its unitholders' equity and non-controlling interest for 2005 by $24.44 million (2004 – $10.15 million) on the Trust's consolidated balance sheet. Consolidated net earnings for 2005 have been reduced for net earnings attributable to the non-controlling interest of $5.99 million (2004 – $1.87 million). In accordance with EIC-151 and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which for 2005 additionally resulted in an increase in property and equipment of $24.93 million (2004 – $11.28 million), and an increase in future income tax liability of $6.48 million (2004 – $3.00 million). Cash flow was not impacted by this change.

The cumulative impact to date of the application of EIC-151 has been to increase gross property and equipment by $36.21 million, (for depletion impact see note 5), unitholders' equity and non-controlling interest by $34.59 million, future income tax liability by $9.48 million and an allocation of net earnings to exchangeable shareholders' of $7.86 million.

4. ACQUISITION

On November 15, 2005, a subsidiary of the Trust acquired all of the outstanding shares of Simoil Resources Ltd. ("Simoil"), a private oil and gas company, for consideration of $1.19 million. Consideration consisted of $0.04 million cash and the issuance of 40,000 Zargon trust units valued at $28.60 per unit.

The results of operations for Simoil have been included in the consolidated financial statements since November 15, 2005.

The acquisition was accounted for by the purchase method as follows:

($ thousand)	2005
Property and equipment	**1,702**
Future income tax liability	**(415)**
Asset retirement obligations	**(101)**
Total consideration	**1,186**

5. PROPERTY AND EQUIPMENT

		December 31, 2005	
($ thousand)	**Cost**	**Accumulated Depletion and Depreciation**	**Net Book Value**
Petroleum, natural gas properties and equipment*	**387,113**	**134,614**	**252,499**
Office equipment	**1,664**	**848**	**816**
	388,777	**135,462**	**253,315**

		December 31, 2004	
($ thousand)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum, natural gas properties and equipment*	306,812	97,680	209,132
Office equipment	1,304	700	604
	308,116	98,380	209,736

* *As a result of shareholders redeeming exchangeable shares, property and equipment has cumulatively increased $36.21 million, $24.93 million relating to 2005 and $11.28 million relating to 2004. The effect of these increases has resulted in additional depletion and depreciation expense of approximately $5.08 million which all relates to 2005.*

At December 31, 2005, petroleum, natural gas properties and equipment include $14.72 million (2004 – $14.70 million) relating to undeveloped properties that have been excluded from the depletion calculation.

An impairment test calculation was performed on the Trust's petroleum, natural gas properties and equipment at December 31, 2005 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Trust's petroleum, natural gas properties and equipment. This impairment calculation was performed separately on both the Canadian and US cost centres. The following table outlines benchmark prices used in the impairment test at December 31, 2005:

Year	WTI Crude Oil ($US/bbl)	Exchange Rate ($US/$Cdn)	WTI Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/gj)
2006	64.37	0.88	73.15	9.93
2007	64.83	0.88	73.67	10.06
2008	62.87	0.88	71.44	9.33
2009	60.69	0.88	68.97	8.50
2010	59.51	0.88	67.62	7.86
Thereafter (inflation %)	2.0%	0.88	2.0%	2.0%

Actual prices used in the impairment test were adjusted for commodity price differentials specific to Zargon.

6. LONG TERM DEBT

On September 30, 2005, a Canadian subsidiary and a US subsidiary of the Trust entered into syndicated committed credit facilities with a borrowing base of $80 million which replaces its former demand facility of $50 million. These facilities consist of a $60 million tranche available to the Canadian borrower and a US $15 million tranche available to the US borrower. A $150 million demand debenture on the assets of the subsidiaries of the Trust has been provided as security for these facilities. The facilities are fully revolving for a 364 day period with the provision for an annual extension at the option of the lenders and upon notice from the Company. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 364 day period. Repayment would not be required until the end of the non-revolving term, and as such, the revolving credit facility has been classified as long term debt. Interest rates fluctuate under the syndicated facility with Canadian prime, US prime, and US base rates plus an applicable margin between zero basis points and 25 basis points, as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 90 basis points and 150 basis points. At December 31, 2005, $10.34 million had been drawn on the syndicated committed credit facilities bearing interest at Canadian prime (December 31, 2005 – 5.0 percent) with any unused amounts subject to standby fees. In the normal course of operations Zargon enters into various letters of credit. At December 31, 2005, the approximate value of outstanding letters of credit totalled $0.47 million (2004 – $0.46 million).

In 2004 and up until September 30, 2005, the Trust had a revolving demand credit facility that provided for a line of credit of $50 million bearing interest at prime (December 31, 2004 – 4.25 percent) and had pledged an assignment of accounts receivable, a first floating charge on all of the Canadian assets and a fixed charge over certain property and equipment as collateral.

7. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by management based on Zargon's net working interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. Zargon has estimated the net present value of its total asset retirement obligations to be $15.86 million (2004 – $14.39 million) as at December 31, 2005, based on a total future liability of $62.54 million (2004 – $59.12 million). These payments are expected to be made over the next 30 years with the majority of the costs being incurred after 2012. Commencing July 1, 2005, incremental asset retirement obligations are calculated using a revised credit adjusted risk-free rate of 7.5 percent. Asset retirement obligations prior to this period were calculated using a credit adjusted risk-free rate of 8.5 percent. An inflation rate of two percent used in the calculation of the present value of the asset retirement obligation remains unchanged. The following table reconciles Zargon's asset retirement obligation:

	Year ended December 31,	
($ thousand)	**2005**	2004
Balance, beginning of year	**14,390**	12,194
Liabilities incurred	**906**	1,696
Liabilities settled	**(604)**	(414)
Accretion expense	**1,196**	1,076
Foreign exchange	**(29)**	(162)
Balance, end of year	**15,859**	14,390

8. UNITHOLDERS' EQUITY

Pursuant to the Plan of Arrangement on July 15, 2004, 14.87 million units of the Trust and 3.66 million exchangeable shares (see note 9) of the Company were issued in exchange for all of the outstanding shares of the Company on a one-for-one basis.

The Trust is authorized to issue an unlimited number of voting trust units.

TRUST UNITS

	December 31, 2005		December 31, 2004	
(thousand)	Number of Units	Amount ($)	Number of Units	Amount ($)
Units issued				
Balance, beginning of year	**15,341**	**45,755**	–	–
Issued pursuant to Plan of Arrangement July 15, 2004	–	–	14,866	36,219
Unit rights exercised for cash	**153**	**2,723**	–	–
Unit-based compensation recognized	–	**725**	–	–
Issued on conversion of exchangeable shares	**821**	**21,297**	475	9,536
Issued on corporate acquisition	**40**	**1,144**	–	–
Balance, end of year	**16,355**	**71,644**	15,341	45,755

COMMON SHARES OF ZARGON OIL & GAS LTD.

	December 31, 2004	
(no par value) (thousand)	Number of Shares	Amount ($)
Shares issued		
Balance, beginning of year	17,992	42,200
Stock options exercised for cash	534	2,867
Stock-based compensation recognized	–	69
Trust units issued	(14,866)	(36,219)
Exchangeable shares issued	(3,660)	(8,917)
Balance, end of year	–	–

COMPENSATION PLANS

A summary of the status of the Trust's compensation expense for the years ended December 31, 2005 and 2004 is presented below:

COMPENSATION EXPENSE

	Year ended December 31,	
($ thousand)	**2005**	2004
Stock-based compensation expense prior to Plan of Arrangement July 15, 2004	–	345
Accelerated vesting of unvested stock options pursuant to the Arrangement	–	2,167
Unit-based compensation recognized subsequent to trust conversion	**902**	1,170
Total for the year	**902**	3,682

 A summary of the status of the Trust's compensation plans as at December 31, 2005 and 2004 and changes during the years ended on those dates is presented below:

TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a unit rights incentive plan (the "Plan") that allows the Trust to issue rights to acquire trust units to directors, officers, employees and service providers. The Trust is authorized to issue up to 1.82 million unit rights, however, the number of trust units reserved for issuance upon exercise of the rights shall not at any time exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust. At the time of grant, unit right exercise prices approximate the market price for the trust units. At the time of exercise, the rights holder has the option of exercising at the original grant price or the exercise price as calculated per the Arrangement. Rights granted under the plan generally vest over a three-year period and expire approximately five years from the grant date.

The following table summarizes information about the Trust's unit rights:

	December 31, 2005		December 31, 2004	
	Number of Unit Rights (thousand)	Weighted Average Exercise Price ($/unit right)	Number of Unit Rights (thousand)	Weighted Average Exercise Price ($/unit right)
Outstanding at beginning of year	579	17.79	–	–
Unit rights granted	505	26.89	579	17.79
Unit rights exercised	(153)	17.77	–	–
Unit rights cancelled	(16)	18.13	–	–
Outstanding at end of year	915	22.80	579	17.79
Unit rights exercisable at year end	48	17.70	–	–

The following table summarizes information about unit rights outstanding at December 31, 2005:

	Unit Rights Outstanding			Unit Rights Exercisable	
Range of Exercise Prices ($/unit right)	Number Outstanding at 12/31/05 (thousand)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price ($/unit right)	Number Exercisable at 12/31/05 (thousand)	Weighted Average Exercise Price ($/unit right)
17.70 – 19.25	411	3.1 years	17.78	48	17.70
22.00	162	4.1 years	22.00	–	–
25.06 – 27.40	171	4.1 years	27.35	–	–
31.09	171	4.1 years	31.09	–	–
	915		22.80	48	17.70

UNIT-BASED COMPENSATION (See Compensation Expense Table Above)

The Plan allows for the exercise price of rights to be reduced in future periods by an amount that distributions exceed a stated return on assets. The unit-based compensation expense arising from unit rights granted upon the July 15, 2004 Plan of Arrangement and up to December 31, 2004 were originally calculated using the intrinsic value method. In response to an emphasis by securities regulators that fair value methodologies be used, new measurement techniques in 2005 have been developed utilizing a fair value option-pricing model for such unit rights grants. Zargon has reassessed the previous unit rights grants under this fair value model and there is no significant impact on amounts previously recorded as 2004 unit-based compensation expense. Zargon will continue to use fair value methodologies, where possible, for future unit rights grants.

The assumptions made for unit rights granted for 2005 include a volatility factor of expected market price of 27.9 percent, a weighted average risk-free interest rate of 3.6 percent, a dividend yield of 7.2 percent and a weighted average expected life of the unit rights of four years, resulting in unit-based compensation expense of $0.90 million. In 2004, subsequent to the Arrangement, $1.17 million of unit-based compensation expense was recognized.

Compensation expense associated with rights granted under the Plan is recognized in earnings on a straight-line basis over the vesting period of the unit rights with a corresponding increase or decrease in contributed surplus. The exercise of trust unit rights is recorded as an increase in trust units with a corresponding reduction in contributed surplus. Forfeiture of rights are recorded as a reduction in expense in the period in which they occur.

STOCK OPTIONS

In 2004, as part of the Arrangement to reorganize Zargon Oil & Gas Ltd. into a Trust, all common share options, vested and unvested, were cancelled and the optionholders received a cash payment for the intrinsic value of the options.

	December 31, 2004	
	Number of Shares (thousand)	Weighted Average Exercise Price ($/stock option)
Outstanding at beginning of year	1,297	7.05
Granted	430	16.00
Exercised	(534)	5.39
Cancelled prior to trust conversion	(9)	9.61
Cancelled immediately prior to trust conversion	(1,184)	11.03
Outstanding at end of year	–	–

STOCK-BASED COMPENSATION (See Compensation Expense Table Above)

Compensation expense of $0.34 million was recognized for the 2004 year as a result of regular vesting of unvested stock options granted prior to the Arrangement. Additionally, as a result of cancelling the stock-option plan pursuant to the Arrangement, compensation expense for the year ended December 31, 2004 of $2.17 million resulted from the acceleration of unvested stock options. Both of these non-cash expenses were recognized as part of unit-based compensation expense on the 2004 income statement for the twelve month period.

Under this stock-option plan, the Company had calculated the value of stock-based compensation using a Black-Scholes option-pricing model to estimate the fair value of stock options at the date of grant.

Compensation expense for options granted under the stock-option plan was based on the estimated fair values at the time of the grant and the expense was recognized over the vesting period of the option.

The assumptions made for the options granted in 2004 include an annualized volatility factor of 26.3 percent, a weighted average risk-free interest rate of 3.3 percent, no dividend yield and a weighted average expected life of options of four years.

The following table summarizes information about the Trust's contributed surplus account:

CONTRIBUTED SURPLUS

($ thousand)

Balance, January 1, 2004	264
Stock-based compensation expense prior to Plan of Arrangement July 15, 2004	345
Stock-based compensation recognized on exercise of stock options	(69)
Accelerated vesting of unvested stock options pursuant to the Arrangement	2,167
Stock-options cancelled immediately prior to trust conversion	(2,707)
Balance at trust conversion	–
Unit-based compensation recognized subsequent to trust conversion	1,170
Balance, December 31, 2004	**1,170**
Unit-based compensation expense	**902**
Unit-based compensation recognized on exercise of unit rights	**(725)**
Balance, December 31, 2005	**1,347**

9. NON-CONTROLLING INTEREST – EXCHANGEABLE SHARES

Zargon Oil & Gas Ltd. is authorized to issue a maximum of 3.66 million exchangeable shares. The exchangeable shares are convertible into trust units at the option of the shareholder based on the exchange ratio, which is adjusted monthly to reflect the distribution paid on the trust units. Cash distributions are not paid on the exchangeable shares. During the year, a total of 0.78 million (2004 – 0.47 million) exchangeable shares were converted into 0.82 million (2004 – 0.48 million) trust units based on the exchange ratio at the time of conversion. At December 31, 2005, the exchange ratio was 1.09629 (2004 – 1.02583) trust units per exchangeable share. As set out in the Arrangement, the exchangeable shares are entitled to vote equally to the number of trust units for which each exchangeable share is convertible into a trust unit on the record date. The Board of Directors of Zargon Oil & Gas Ltd. hold the option to redeem all outstanding exchangeable shares for trust units on or before July 15, 2014. At such time, should the Board not extend the term of the shares, there will be no remaining non-controlling interest.

The Trust retroactively applied EIC-151 "Exchangeable Securities Issued by a Subsidiary of an Income Trust" in 2004. Per EIC-151, if certain conditions are met, the exchangeable shares issued by a subsidiary must be reflected as non-controlling interest on the consolidated balance sheet and in turn, net earnings must be reduced by the amount of net earnings attributed to the non-controlling interest.

The non-controlling interest on the consolidated balance sheet consists of the book value of exchangeable shares at the time of the Plan of Arrangement, plus net earnings attributable to the exchangeable shareholders, less exchangeable shares (and related cumulative earnings) redeemed. The net earnings attributable to the non-controlling interest on the consolidated statement of earnings represents the cumulative share of net earnings attributable to the non-controlling interest based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each period end.

NON-CONTROLLING INTEREST – EXCHANGEABLE SHARES

(thousand, except exchange ratio)	December 31, 2005 Number of Shares	December 31, 2005 Amount ($)	December 31, 2004 Number of Shares	December 31, 2004 Amount ($)
Non-controlling interest – exchangeable shares issued				
Balance, beginning of year	**3,186**	**9,529**	–	–
Issued pursuant to Plan of Arrangement July 15, 2004	**–**	**–**	3,660	8,917
Exchanged for trust units at book value and including earnings attributed since Plan of Arrangement	**(784)**	**(2,850)**	(474)	(1,258)
Earnings attributable to non-controlling interest	**–**	**5,994**	–	1,870
Balance, end of year	**2,402**	**12,673**	3,186	9,529
Exchange ratio, end of year	**1.09629**		1.02583	
Trust units issuable upon conversion of exchangeable shares, end of year	**2,633**		3,268	

The proforma total units outstanding at year end, including trust units outstanding, and trust units issuable upon conversion of exchangeable shares and after giving rise to the exchange ratio at the end of the year is 18.99 million units (2004 – 18.61 million units).

Immediately prior to the July 15, 2004 Plan of Arrangement, the Company had $45.14 million in share capital. Upon conversion to the Trust structure these amounts were allocated $36.22 million to trust units and $8.92 million to exchangeable shares, based on the terms of the Arrangement.

The effect of EIC-151 on Zargon's unitholders' capital and exchangeable shares is as follows:

($ thousand)	Zargon Oil & Gas Ltd. Common Shares	Zargon Energy Trust Units	Zargon Oil & Gas Ltd. Exchangeable Shares	Total
Immediately prior to July 15, 2004 Plan of Arrangement	45,136			
Plan of Arrangement July 15, 2004	(45,136)	36,219	8,917	
	–	36,219	8,917	45,136
Issued on redemption of exchangeable shares at book value	–	1,155	(1,155)	–
Effect of EIC-151	–	8,381	1,767	10,148
Balance at December 31, 2004	**–**	**45,755**	**9,529**	**55,284**
Issued on redemption of exchangeable shares at book value	**–**	**1,909**	**(1,909)**	**–**
Effect of EIC-151	**–**	**19,388**	**5,053**	**24,441**
Unit-based compensation recognized	**–**	**725**	**–**	**725**
Unit rights exercised for cash	**–**	**2,723**	**–**	**2,723**
Issued on corporate acquisition	**–**	**1,144**	**–**	**1,144**
Balance at December 31, 2005	**–**	**71,644**	**12,673**	**84,317**

10. INCOME TAXES

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust allocates all of its Canadian taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no current tax provision for Canadian income tax expense has been made in the Trust. Canadian Large Corporations tax, capital taxes, and US income taxes are provided for under current income tax expense.

In the Trust structure, payments are made between the Company and the Trust that result in the transferring of taxable income from the Company to individual unitholders. These payments may reduce future income tax liabilities previously recorded by the Company that would be recognized as a recovery of income tax in the period incurred.

Income taxes differ from the amounts which would be obtained by applying statutory income tax rates to earnings before income taxes as follows:

($ thousand)	2005	2004
Statutory income tax rate	**38.86%**	39.96%
Expected income taxes	**16,958**	13,289
Add (deduct) income tax effect of:		
Non-deductible Crown charges, net of Alberta Royalty Credit	**5,058**	4,928
Resource allowance	**(5,062)**	(4,438)
Rate adjustment	**(1,674)**	947
Cash distributions	**(14,551)**	(4,277)
Large corporation tax, capital taxes, and US income taxes	**1,801**	1,114
Other	**(255)**	(810)
	2,275	10,753

As at December 31, 2005, Zargon has exploration and development costs, unamortized petroleum and natural gas property expenditures, undepreciated capital costs and unamortized share issue costs available for deduction against future taxable earnings in aggregate of approximately $90 million (2004 – $79 million).

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of Zargon's net future income tax liability are as follows:

($ thousand)	2005	2004
Net book value of property and equipment in excess of tax pools	**46,088**	33,279
Deferred partnership earnings	**10,178**	14,153
Asset retirement obligation	**(5,631)**	(5,107)
Unrealized risk management liability	**(1,319)**	–
Share issue costs	**(19)**	(126)
Alberta Royalty Credit	**(369)**	(369)
	48,928	41,830

11. WEIGHTED AVERAGE NUMBER OF TOTAL UNITS

(thousand)	2005 (units)	2004 (units)
Basic	**16,003**	16,818
Diluted	**18,848**	18,723

Dilution amounts of 2.85 million units (2004 – 1.91 million) were added to the weighted average number of units outstanding during the year in the calculation of diluted per unit amounts. These unit additions represent the dilutive effect of unit rights according to the treasury stock method, and also include exchangeable shares using the "if-converted" method. An adjustment to the numerator amount was required in the diluted calculation to provide for the earnings of $5.99 million (2004 – $1.87 million) attributable to the non-controlling interest pertaining to the exchangeable shareholders.

12. FINANCIAL INSTRUMENTS

FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

Financial instruments of the Trust consist of accounts receivable, deposits, bank indebtedness, accounts payable, cash distributions payable, unrealized risk management liability and long term debt. As at December 31, 2005 and 2004, there are no significant differences between the carrying values of these amounts and their estimated market values.

CREDIT RISK MANAGEMENT

Accounts receivable include amounts receivable for petroleum and natural gas sales that are generally made to large credit-worthy purchasers, and amounts receivable from joint venture partners that are recoverable from production. Accordingly, the Trust views credit risks on these amounts as low. Of Zargon's significant individual accounts receivable at December 31, 2005, approximately 32 percent was owing from one company (2004 – 28 percent).

The Trust is exposed to losses in the event of non-performance by counterparties to financial risk management contracts. The Trust minimizes credit risk associated with possible non-performance to these financial instruments by entering into contracts with only investment grade counterparties, limits on exposures to any one counterparty, and monitoring procedures. The Trust believes these risks are minimal.

INTEREST RATE RISK MANAGEMENT

Borrowings under bank credit facilities are market-rate-based (variable interest rates); thus carrying values approximate fair values.

FOREIGN CURRENCY RISK MANAGEMENT

The Trust is exposed to fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil, and to a large extent natural gas prices, are based upon reference prices denominated in US dollars, while the majority of the Trust's expenses are denominated in Canadian dollars. When appropriate, the Trust enters into agreements to fix the exchange rate of Canadian dollars to US dollars in order to manage this risk.

COMMODITY PRICE RISK MANAGEMENT

The Trust is a party to certain financial instruments that have fixed the price of a portion of its oil and natural gas production. The Trust enters into these contracts for risk management purposes only, in order to protect a portion of its future cash flow from the volatility of oil and natural gas commodity prices. The Trust has outstanding contracts at December 31, 2005 as follows:

FINANCIAL CONTRACTS DESIGNATED AS HEDGES AT DECEMBER 31, 2005:

	Rate	Price	Range of Terms	Fair Market Value Gain/(Loss) ($ thousand)
Oil collar	200 bbl/d	$36.00 US/bbl Put $48.40 US/bbl Call	Jan. 1/06–Jun. 30/06	(595)
Natural gas collar	3,000 gj/d	$5.90/gj Put $10.00/gj Call	Jan. 1/06–Mar. 31/06	(13)
Total Fair Market Value, Financial Contracts Designated as Hedges				**(608)**

FINANCIAL CONTRACTS NOT DESIGNATED AS HEDGES AT DECEMBER 31, 2005:

	Rate	Price	Range of Terms	Fair Market Value Gain/(Loss) ($ thousand)
Oil swaps	200 bbl/d	$48.50 US/bbl	Jan. 1/06–Jun. 30/06	(591)
	300 bbl/d	$51.83 US/bbl	Jan. 1/06–Dec. 31/06	(1,447)
	200 bbl/d	$51.12 US/bbl	Jul. 1/06–Dec. 31/06	(547)
Oil collars	200 bbl/d	$40.00 US/bbl Put $49.05 US/bbl Call	Jan. 1/06–Jun. 30/06	(568)
	200 bbl/d	$52.00 US/bbl Put $78.95 US/bbl Call	Jan. 1/06–Dec. 31/06	–
	200 bbl/d	$55.00 US/bbl Put $78.05 US/bbl Call	Jul. 1/06–Dec. 31/06	–
Natural gas swaps	1,000 gj/d	$12.82/gj	Jan. 1/06–Mar. 31/06	249
	4,000 gj/d	$9.31/gj	Apr. 1/06–Oct. 31/06	(501)
Natural gas collars	2,000 gj/d	$6.50/gj Put $8.80/gj Call	Jan. 1/06–Mar. 31/06	(225)
	2,000 gj/d	$7.00/gj Put $9.35/gj Call	Jan. 1/06–Mar. 31/06	(126)
	1,000 gj/d	$9.50/gj Put $12.50/gj Call	Nov. 1/06–Mar. 31/07	–
	1,000 gj/d	$10.50/gj Put $13.18/gj Call	Nov. 1/06–Mar. 31/07	–
Total Fair Market Value, Financial Contracts Not Designated as Hedges				**(3,756)**

PHYSICAL CONTRACTS AT DECEMBER 31, 2005:

	Rate	Price	Range of Terms	Fair Market Value Gain/(Loss) ($ thousand)
Natural gas fixed price	4,000 gj/d	$7.92/gj	Apr. 1/06–Oct. 31/06	(1,692)
Natural gas collars	1,000 gj/d	$8.47/gj Put $9.50/gj Call	Jan. 1/06–Mar. 31/06	(49)
	1,000 gj/d	$8.50/gj Put $12.85/gj Call	Nov. 1/06–Mar. 31/07	–
	1,000 gj/d	$9.50/gj Put $13.50/gj Call	Nov. 1/06–Mar. 31/07	–
Total Fair Market Value, Physical Contracts				**(1,741)**

Oil swaps and collars are settled against the NYMEX pricing index, whereas natural gas swaps, collars, and puts are settled against the AECO pricing index.

Financial risk management contracts in place as at December 31, 2004 were designated as hedges for accounting purposes and the Trust continues to monitor these contracts in determining the continuation of hedge effectiveness. For these contracts, realized gains and losses are recorded in the statement of earnings as the contracts settle and no unrealized gain or loss is recognized. The realized losses for 2005 were $7.75 million (2004 – $4.57 million). At December 31, 2005, an additional $0.61 million would have been required to settle the above designated hedge contracts which all related to financial hedges. At December 31, 2004, $1.14 million would have been received to settle the designated hedge contracts, of this amount $0.71 million related to financial hedges and $0.43 million related to physical hedges. Contracts settled by way of physical delivery are recognized as part of the normal revenue stream. These instruments have no book values recorded in the consolidated financial statements.

For financial risk management contracts entered into after December 31, 2004, the Trust does consider these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and accordingly, for outstanding contracts not designated as hedges, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at the period end. The unrealized losses as at December 31, 2005 were $3.76 million (2004 – nil). These instruments have been recorded as a liability in the consolidated balance sheet.

13. COMMITMENTS

The Trust is committed to future minimum payments for natural gas transportation contracts in addition to operating leases for office space, office equipment, vehicles and field equipment. Payments required under these commitments for each of the next four years are: 2006 – $1.44 million; 2007 – $0.57 million; 2008 – $0.07 million; 2009 – $0.02 million.

14. CONTINGENCIES AND GUARANTEES

In the normal course of operations, Zargon executes agreements that provide for indemnification and guarantees to counterparties in transactions such as the sale of assets and operating leases.

These indemnifications and guarantees may require compensation to counterparties for costs and losses incurred as a result of various events, including breaches of representations and warranties, loss of or damages to property, environmental liabilities or as a result of litigation that may be suffered by counterparties.

Certain indemnifications can extend for an unlimited period and generally do not provide for any limit on the maximum potential amount. The nature of substantially all of the indemnifications prevents the Trust from making a reasonable estimate of the maximum potential amount that might be required to pay counterparties as the agreements do not specify a maximum amount, and the amounts depend on the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time.

The Trust indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their service to the Trust to the extent permitted by law. The Trust has acquired and maintains liability insurance for its directors and officers. The Trust is party to various legal claims associated with the ordinary conduct of business. The Trust does not anticipate that these claims will have a material impact on the Trust's financial position.

15. CHANGE IN NON-CASH WORKING CAPITAL

	Year ended December 31,	
($ thousand)	**2005**	2004
Changes in non-cash working capital items:		
Accounts receivable	**(7,560)**	(2,092)
Prepaid expenses and deposits	**243**	(1,973)
Accounts payable and accrued liabilities	**6,417**	4,876
Cash distributions payable	**8,912**	2,210
Other	**(230)**	(57)
	7,782	2,964
Changes relating to operating activities	**(1,401)**	19
Changes relating to financing activities	**8,974**	2,148
Changes relating to investing activities	**209**	797
	7,782	2,964

16. SUPPLEMENTAL CASH FLOW INFORMATION

($ thousand)	**2005**	2004
Cash interest and financing charges paid	**1,044**	448
Cash taxes paid	**1,911**	794

17. SEGMENTED INFORMATION

Zargon's entire operating activities are related to exploration, development and production of oil and natural gas in the geographic segments of Canada and the US.

	2005		
($ thousand)	**Canada**	**United States**	**Combined**
Petroleum and natural gas revenue	**141,869**	**20,853**	**162,722**
Earnings before income taxes	**34,890**	**8,748**	**43,638**
Property and equipment, net	**221,664**	**31,651**	**253,315**
Total assets	**244,416**	**33,444**	**277,860**
Net capital expenditures [1]	**49,251**	**5,433**	**54,684**

	2004		
($ thousand)	Canada	United States	Combined
Petroleum and natural gas revenue	108,484	15,484	123,968
Earnings before income taxes	27,614	5,641	33,255
Property and equipment, net	184,860	24,876	209,736
Total assets	200,171	26,793	226,964
Net capital expenditures	51,464	4,809	56,273

1. Amounts include capital expenditures acquired for cash and equity issuances.

18. ACCUMULATED CASH DISTRIBUTIONS

During the year, the Trust paid or declared distributions to the unitholders in the aggregate amount of $37.44 million (2004 – $10.70 million) in accordance with the following schedule:

2005 Distributions	Record Date	Distribution Date	Per Trust Unit
January 2005	January 31, 2005	February 15, 2005	$0.14
February 2005	February 28, 2005	March 15, 2005	$0.14
March 2005	March 31, 2005	April 15, 2005	$0.14
April 2005	April 30, 2005	May 16, 2005	$0.14
May 2005	May 31, 2005	June 15, 2005	$0.14
June 2005	June 30, 2005	July 15, 2005	$0.14
July 2005	July 31, 2005	August 15, 2005	$0.14
August 2005	August 31, 2005	September 15, 2005	$0.16
September 2005	September 30, 2005	October 17, 2005	$0.16
October 2005	October 31, 2005	November 15, 2005	$0.16
November 2005	November 30, 2005	December 15, 2005	$0.18
December 2005	December 31, 2005	January 16, 2006	$0.18
December 2005	December 31, 2005	January 16, 2006	$0.50

2004 Distributions	Record Date	Distribution Date	Per Trust Unit
August 2004	August 31, 2004	September 15, 2004	$0.14
September 2004	September 30, 2004	October 15, 2004	$0.14
October 2004	October 31, 2004	November 15, 2004	$0.14
November 2004	November 30, 2004	December 15, 2004	$0.14
December 2004	December 31, 2004	January 17, 2005	$0.14

19. ZARGON ENERGY TRUST REORGANIZATION

In 2004, the following costs were incurred to reorganize Zargon Oil & Gas Ltd. into a trust effective July 15, 2004:

($ thousand)	
Cash payout of stock options	7,875
Financial advisory, accounting and legal fees, and preparation and printing of the Information Circular	1,568
Total reorganization costs	9,443

Of the above amounts, $2.71 million was charged to contributed surplus relating to recognized stock-based compensation under the previous stock option plan for the Company. The remaining $6.73 million ($6.24 million net of taxes) was charged directly against accumulated earnings.

20. RELATED PARTY TRANSACTIONS

Zargon paid $0.13 million (2004 – $0.15 million) in consulting fees to a company owned by the Chairman of the Board; $0.04 million (2004 – $0.05 million) for vehicle leases to a company owned by a Board member; and $0.12 million (2004 – $0.53 million) for legal services to a law firm in which a Board member is a partner. These payments were in the normal course of operations, on commercial terms, and therefore were recorded at the exchange amount.

21. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with the current year's financial statement presentation.

SIX-YEAR SUMMARY

	2005	2004	2003	2002	2001	2000
FINANCIAL ($ thousand, except per unit amounts)						
Petroleum and natural gas revenue	**162,722**	123,968	101,657	65,538	63,795	53,306
Less expenses – cash items						
Royalties (net of Alberta Royalty Credit)	**37,319**	28,047	22,508	13,508	14,222	10,716
Production	**24,035**	21,692	17,201	15,649	11,933	8,615
General and administrative	**6,053**	4,358	3,542	3,455	3,083	2,189
Realized risk management (gain)/loss	**7,754**	4,568	2,882	(669)	573	2,733
Interest and financing charges	**786**	440	771	1,100	957	1,269
Current and capital taxes	**1,801**	1,114	406	378	358	288
Cash flow from operations	**84,974**	63,749	54,347	32,117	32,669	27,496
Less expenses – non-cash items						
Depletion, depreciation and foreign exchange	**37,283**	26,850	19,363	14,148	11,067	7,061
Unrealized risk management loss	**3,756**	–	–	–	–	–
Future income tax	**474**	9,639	9,187	6,558	7,860	8,706
Accretion of asset retirement obligations	**1,196**	1,076	1,172	715	520	479
Unit-based compensation	**902**	3,682	264	–	–	–
Earnings before non-controlling interest	**41,363**	22,502	24,361	10,696	13,222	11,250
Less non-controlling interest – exchangeable shares	**5,994**	1,870	–	–	–	–
Net earnings	**35,369**	20,632	24,361	10,696	13,222	11,250
Per unit, diluted						
Cash flow from operations	**4.51**	3.40	2.96	1.81	2.03	1.86
Net earnings	**2.19**	1.20	1.33	0.60	0.82	0.76
Net capital expenditures	**54,684**	56,273	39,909	35,548	55,176	30,514
Cash distributions	**37,444**	10,702	–	–	–	–
Cash distributions ($/trust unit)	**2.32**	0.70	–	–	–	–
Balance sheet at year end						
Property and equipment, net	**253,315**	209,736	167,888	147,404	124,020	78,030
Bank debt	**10,339**	14,230	6,978	25,279	24,137	15,902
Unitholders' equity	**144,613**	120,622	112,469	86,699	70,072	42,510
Unitholders' equity ($/total units)	**7.62**	6.48	6.25	4.92	4.20	2.97
Year end total units outstanding (thousand)	**18,988**	18,610	17,992	17,637	16,666	14,315
OPERATING						
Total production (boe/d)	**8,342**	8,222	7,446	6,349	5,553	4,140
Oil and liquids (bbl/d)	**3,697**	3,416	3,287	2,968	2,441	1,725
Natural gas (mmcf/d)	**27.87**	28.84	24.95	20.29	18.67	14.49
Equivalent per million total units (boe/d)	**445**	447	418	368	357	287
Total proved reserves (mboe)	**19,243**	19,049	18,664	21,592	20,320	15,878
Proved oil and liquids (mbbl)	**11,490**	10,954	10,505	11,114	10,482	6,340
Proved natural gas (bcf)	**46.52**	48.57	48.96	62.87	59.03	57.23
Total proved and probable reserves (mboe)	**26,771**	25,955	24,745	23,983	22,859	18,343
Proved and probable oil and liquids (mbbl)	**15,354**	14,361	13,566	12,445	11,948	7,508
Proved and probable natural gas (bcf)	**68.50**	69.56	67.07	69.23	65.47	64.96
Equivalent per total unit (boe)	**1.41**	1.39	1.38	1.36	1.37	1.28
Average selling price before risk management gains or losses						
WTI crude oil price ($US/bbl)	**56.56**	41.40	31.04	26.08	25.90	30.20
FOB Edmonton crude oil price ($/bbl)	**68.72**	52.54	43.14	39.94	39.18	44.33
Zargon field oil and liquids price ($/bbl)	**57.15**	45.37	36.66	34.45	31.86	40.73
NYMEX Henry Hub average spot natural gas price ($US/mmbtu)	**8.89**	5.90	5.49	3.35	3.94	4.31
Alberta AECO average spot natural gas price ($/mmbtu)	**8.77**	6.55	6.70	4.18	5.43	5.60
Zargon field natural gas price ($/mcf)	**8.41**	6.37	6.33	3.81	5.19	5.20
Other data						
Wells drilled, net	**53.5**	49.5	38.6	31.6	47.7	38.6
Undeveloped land (thousand net acres)	**367**	376	398	331	241	213
Closing trust unit price ($/unit)	**31.75**	23.85	13.50	9.00	7.20	4.45

NOTES:

Throughout this summary, the calculation of barrels of oil equivalent (boe) is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil.

Cash flow from operations is a non-GAAP term that represents net earnings except for non-cash items. For a further discussion about this term, refer to page 29 of the report.

For net capital expenditures, amounts include capital expenditures acquired for cash and equity issuances.

Cash distributions to unitholders commenced subsequent to the reorganization of the Company into a Trust effective July 15, 2004.

Total units outstanding include trust units plus exchangeable shares outstanding at period end. The exchangeable shares are converted at the exchange ratio at the end of the period.

Average daily production per million units is calculated using the weighted average number of units outstanding during the period plus the weighted average number of exchangeable shares outstanding for the period converted at the average exchange ratio for the period.

In this table the established reserves (proved plus 50 percent probable) for the prior years (2000-2002) are used as a comparison to 2003, 2004 and 2005 proved and probable reserves. This adjustment is necessary due to the change in reserve risk assessments required to comply with NI 51-101 reserve guidelines.

Certain comparative period numbers reflect retroactive restatement due to a change in accounting policy.

CORPORATE INFORMATION

BOARD OF DIRECTORS

Craig H. Hansen
Calgary, Alberta

K. James Harrison[3][4]
Oakville, Ontario

H. Earl Joudrie[3]
Toronto, Ontario

Kyle D. Kitagawa[1]
Calgary, Alberta

James J. Lawson[3]
Oakville, Ontario

John O. McCutcheon
Chairman of the Board
Vancouver, British Columbia

Jim Peplinski[2][4]
Calgary, Alberta

J. Graham Weir[1][2]
Calgary, Alberta

William J. Whelan[1][4]
Calgary, Alberta

Grant A. Zawalsky[2][3]
Calgary, Alberta

OFFICERS

Craig H. Hansen
President and Chief Executive Officer

Brent C. Heagy
Vice President, Finance and Chief Financial Officer

Mark I. Lake
Vice President, Exploration

Daniel A. Roulston
Executive Vice President, Operations

Sheila A. Wares
Vice President, Accounting

Kenneth W. Young
Vice President, Land

1 Audit Committee
2 Reserves Committee
3 Governance and Nominating Committee
4 Compensation Committee

STOCK EXCHANGE LISTING

The Toronto Stock Exchange

Zargon Energy Trust
Trust Units
Trading Symbol: ZAR.UN

Zargon Oil & Gas Ltd.
Exchangeable Shares
Trading Symbol: ZOG.B

TRANSFER AGENT

Valiant Trust Company
310, 606 - 4th Street S.W.
Calgary, Alberta T2P 1T1

BANKER

The Toronto Dominion Bank
910, 333 - 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

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ANNUAL MEETING

The annual meeting of the Unitholders of Zargon Energy Trust will be held on Thursday, April 27, 2006 at 2:00 pm (Calgary time) in the Grand Lecture Theatre of the Metropolitan Conference Centre, 333 - 4th Avenue S.W., Calgary, Alberta.

ABBREVIATIONS

bbl	Barrel
bbl/d	Barrels per day
bcf	Billion cubic feet
boe	Barrels of oil equivalent (6 mcf is equivalent to 1 bbl)
boe/d	Barrels of oil equivalent per day
btu	British thermal units
FD&A	Finding, development and acquisition
gj	Gigajoule
gj/d	Gigajoules per day
m	Thousand
mm	Million
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
PV	Present value
PVBT	Present value before tax

FORWARD-LOOKING STATEMENTS

This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this annual report are as of March 13, 2006 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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